Notice of Construction (NOC) Worksheet

pscleanair.org
Puget Sound Clean Air Agency

Applicant: Puget Sound Energy	**NOC Number**: 11386
Project Location: 1001 E Alexander Ave. Tacoma WA 98421	**Registration Number**: 30022
Applicant Name and Phone: Keith Faretra, (425) 456-2688	**NAICS:** 221210
Engineer: Ralph Munoz	**Inspector**: Wellington Troncoso

A. DESCRIPTION

For the Order of Approval:
One liquefied natural gas (LNG) processing facility and Totem Ocean Trailer Express (TOTE) Marine Vessel LNG fueling system. The LNG processing facility includes the use of the following equipment: one 66 MMBtu/hr LNG vaporizer, enclosed ground flare with four burners, one 9 MMbtu/hr water propylene glycol pretreatment heaters, one 1.6 MMbtu/hr regeneration pretreatment heaters, and one 8 Million gallon LNG storage tank.

Additional Information

Facility: Puget Sound Energy (PSE) LNG facility is being built to provide natural gas to sources around the Tacoma area. The LNG plant plans to supply natural gas during times of peak demand, if necessary, and during non-peak times the plant liquefies natural gas for storage. PSE will use the stored LNG to provide fuel to local businesses, including TOTE (Totem Ocean Trailer Express), a local shipping company operating cargo ships between Tacoma and Alaska.

PSE's application included the following equipment:

LNG storage tank (Application Section 2.1.4)
Propane, isopentane & ethylene storage tanks (Application Section 2.2)
Valves and flanges associated with LNG transfer to and from LNG storage tank (Application Section 2.12.3)
Gas pretreatment system (see application Section 2.1.2)
Gas liquefaction system (see application Section 2.1.3)
LNG vaporization system (see application Sections 2.1.5.1 and 2.2.1)
Boil off/flash gas recovery system (see application Section 2.1.3, 2.1.4 and 2.1.5.3)
Facility cooling water system – This is a closed system that circulates a coolant mixture of water and propylene glycol with no emissions. Heat is collected from various facility equipment, and is rejected to atmosphere via a dry (fin fan air cooled) heat exchanger. The facility will not have a wet cooling tower. It will operate year round to support the facility's various gas compression, cooling, condensing, liquefaction, holding, and boil-off gas recovery operations. The system will have no emissions subject to permitting.
Enclosed ground flare (pilot and burners) (see application Section 2.2.2)
Heavy hydrocarbon and fuel gas collection and storage system (see application Section 2.1.2)
Control building – This building will contain instrument air compressors, a water demineralization system, computer/network servers and human machine interface systems (work stations) and staff that will operate/control the facility's equipment. It will have no emission sources other than space heating.
Storage building –This is an existing structure at the project site. It will house materials, spare parts and supplies for facility maintenance and support. It will have no emissions sources subject to permitting.
Compressor building –This building will house compressors for natural gas liquefaction and boil off/ flash gas recovery that are addressed in Application Sections 2.1.3 and 2.2.3.
Power distribution center – This will be a prefabricated building that houses electrical distribution systems, motor control centers, and other distribution panels and components. Electrical power transformers outside the building will be used to step down voltage levels for utilization within the facility. Between the power distribution center and Tacoma Power's electrical power substation, there will be outdoor high-voltage switch gear. This area will have no emission sources subject to permitting.
Valves and flanges associated with pipeline from Tacoma LNG to TOTE terminal (see application Section 2.1.5.2)
TOTE terminal (see application Section 2.1.5.2)
Ship fueling (bunkering) arm(s) at Tote terminal (see application Section 2.1.5.2)
Truck loading racks (see application Section 2.1.5.3)
Emergency Generator (see application Sections 2.2)
Exempt emissions equipment is listed in Application Section 3, Table 5

Each piece of equipment listed above was evaluated by the Agency in this worksheet to determine exemption status under Reg 1, Section 6.03(c) as well as all emissions from these sources.

From the equipment listed above, the following are considered air emission sources and are all evaluated in this worksheet:

One 66 MMBtu/hr LNG vaporizer,
One enclosed ground flare with four different burners,
Valves and flanges (fugitive emission leaks)

-The following storage tank equipment is considered exempt, per Regulation 1 Section 6.03(c)(78):

Propane Storage Vessel: 1,000 gallons
Iso-Pentane Storage Vessel: 1,000 gallons
Ethylene Storage Vessel: 2,760 gallons
Heavies Storage Vessel: 4,650 gallons.
LNG storage Tank: 8 million gallons

-The truck loading racks are also exempt per Regulation 1, Section 6.03 (c)(79) and (80) since the LNG storage tank is exempt and is less than 0.5 psia true vapor pressure.

-The 1500 kW emergency engine is exempt Per Regulation 1, Section 6.03 (c)(3).

-The following fuel burning equipment are exempt per Regulation 1 Section 6.03(1)(A)
One 9 MMbtu/hr water propylene glycol pretreatment heater,
One 1.6 MMbtu/hr regeneration pretreatment heater

-The Cooling Water system is a forced draft, air-cooled exchanger that recirculates a water/propylene glycol mixture to transfer heat away from natural gas liquefaction equipment. The system is a closed loop system and does not directly come into contact with any exchanger process fluid and therefore has no emissions.

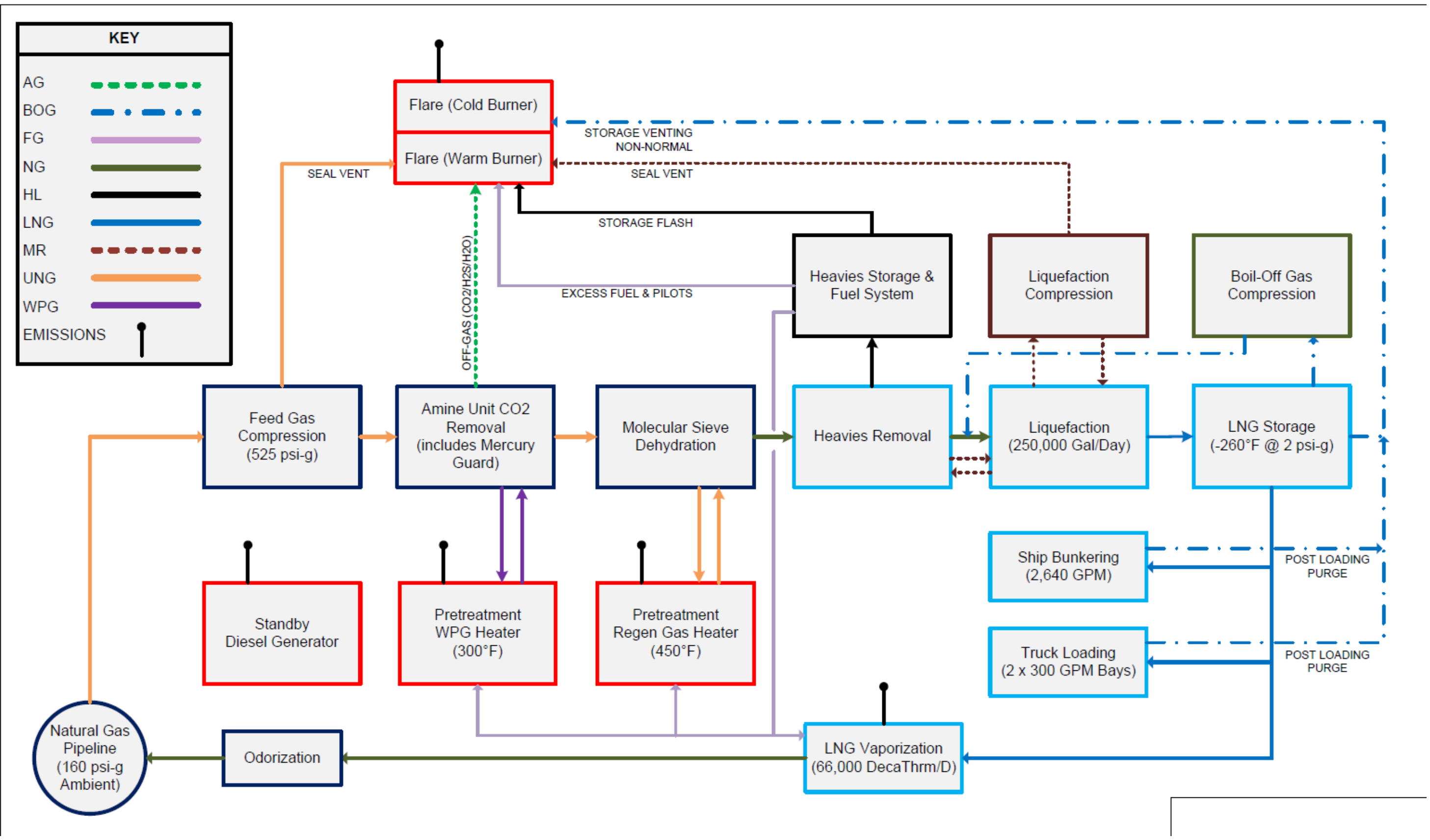
There are no emissions associated with the Compressor Station building, Power distribution building, or the TOTE terminal.

The TOTE marine bunkering system has been designed to operate in a manner where there are no vapors emitted. The bunkering system tanks (TOTE and PSE), associated piping, connection manifolds and hoses do not vent to atmosphere. The system is a closed loop system, and all vaporized LNG Is returned to the plant in a designated vapor return line. When LNG vessel fueling is complete, nitrogen is used to displace any remaining fuel and vapor in all associated piping and fuel hoses. The nitrogen acts to inert the fueling system and all nitrogen purge vapor in the return line was assumed to be routed to the flare for conservative emission estimates. The return system is designed to move gas vapor to the facility or to the flare. As fueling occurs for the marine vessel, there is potential for heat loss which could cause some of the LNG to vaporize. This vaporized LNG is routed back to the liquefaction (LNG storage) tank, but is not accounted for in the emission calculations for conservative purposes.

All underground piping in the TOTE marine bunkering system will be vacuum jacketed to prevent as much heat transfer as possible. Vacuum jacketed means there will be concentric piping around the LNG piping and the annular space between the two pipes will be kept under constant vacuum. PSE will use a vacuum integrity monitoring system to ensure the vacuum remains intact. Fiber optic leak detection is planned to be installed below the LNG lines which are located underground in a sealed casing, as a backup system to ensure there are no leaks from the underground bunkering system piping. Aboveground LNG piping is insulated stainless steel with leak detection via fixed hydrocarbon sensors.

As a result, the potential air emissions associated with nitrogen purging being routed to the flare is outlined in this worksheet.

The process flow diagram for this facility was provided in the application as shown below:



B. DATABASE INFORMATION

NSPS	**Yes**
NESHAP	**No**
Synthetic Minor	**No**

The LNG Vaporizer is subject to 40 CFR 60 Subpart Dc (NSPS) – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. See federal regulation section for more discussion.

C. NOC FEES AND ANNUAL REGISTRATION FEES

NOC Fees:

Fee Description	Cost	Amount Received (Date)
Filing Fee	$ 1,150	
Equipment 1- 1 LNG facility with valve/flanges/seal leaks 2- 66 MMbtu/hr LNG vaporizer 3- 1 enclosed ground flare 4- 1 Feed Gas Compression System 5- 1Amine Unit CO2 Remover 6- 1 Heavies storage/removal system 7- 1 liquefaction compression vent)	$4,200	
SEPA Determination w/ contractor, SEIS (GHG)	Fees Paid	
NSPS Dc	$1,000	
Public Notice Fees	$700+$2,000 + Publication fees (TBD)	
Filing received		$ 1,150 (5/22/17)
Additional fee received		$5,200 (10/3/17)
		$2,700 (7/6/19) + Publication Fees (DUE)
Total		

Paid 10/3/17 $5,200 with receipt 98990
Sent new invoice for $2,700 on 6/26/19, paid on 7/6/19 with receipt 100402.
Publication fees unknown at this time, will invoice after public notice/hearing.

Registration Fees:

Applicability		
Regulation I	Description	Note
Reg 1, 5.03 (a)(1)	Facilities subject to a federal emission standard	
Reg 1, 5.03(a)(4)(C)	Facilities with fuel burning equipment	
Reg 1, 5.07 (c)	Standard fee	
Annual Registration Fee		
Regulation I	Description	Fee
Reg I, 5.07(c)(1) - 40	CFR 60 Subpart Dc	$2,100
Reg 1, 5.07 (c)	Base Fee	$1,150
	Total =	$3,250

D. STATE ENVIRONMENTAL POLICY ACT (SEPA) REVIEW

Regulation I, Article 2 includes the Puget Sound Clean Air Agency SEPA rules, along with the adoption by reference of sections of Chapter 197-11 of the WAC. SEPA requires the Agency to consider the environmental impacts of a proposed project before an order of approval is issued. SEPA review is required for applications which involve a government "action" as defined in SEPA rules (categorical SEPA exemptions are listed in WAC 197-11-800 through -890). Projects requiring an air permit are not categorically exempt under WAC 197-11-800(1)(a)(iii) and (2)(a)(iii) – projects that require a license governing emissions to air except variances and open burning permits.

The PSE LNG facility was reviewed under SEPA by the City of Tacoma which resulted in the production and issuance of a final Environmental Impact Statement (FEIS) for the project on November 9, 2015. It is on the City's website here:

http://www.cityoftacoma.org/cms/One.aspx?portalId=169&pageId=113675

The Agency reviewed the FEIS to ensure that the proposed facility included impacts from what is currently being proposed. This FEIS covered all the equipment that is contained in this Notice of construction permit application. A few of the items in the FEIS are no longer being considered or have changed, and PSE was asked to explain the differences. See their response below:

"In completing the SEPA process, PSE conservatively outlined a facility design anticipated to reflect the highest impact configuration. Since the FEIS was issued by the City of Tacoma on November 9, 2015, PSE has worked to refine the design in ways that reduce the overall facility impacts. In Table 2 below we summarize the primary changes between the FEIS and the NOC application.

Change from FEIS to NOC Application	*Explanation*	*FEIS Reference*
Production capacity	*Daily LNG production capacity has been reduced from 500,000 gallons in the FEIS to 250,000 gallons for the NOC to reflect current facility design.*	*FEIS Section 2.2.1.1 Overview (p.2-1)*
Incoming natural gas composition variability	*Additional design features were added to address possible variations in levels of ethane and propane in natural gas.*	*FEIS Section 2.2.1.7 Other Process Facilities – Heavy Hydrocarbon Collection and Storage System (p.2-6)*
Refrigerant losses	*The FEIS assessed 77 tons/year of refrigerant losses (VOC) as a component of normal operation. PSE revised the design to employ a sealed refrigerant system from which no fugitive emissions will occur.*	*FEIS Table 3.2-3 Potential Emissions for Tacoma LNG and TOTE Marine Vessel LNG Fueling System (Fugitives) (p-3.2-11)*

Flare	*The facility's flare configuration changed from two flares in the FEIS to a single ground flare, as it was determined that the second emergency flare is not needed. In addition, the ground flare design has been improved to include features such as low NOx burners.*	*FEIS Section 2.2.1-7 Other Process Facilities – Flare System (p.2-6)*

In addition to the changes above, some of the modeling conducted (See PSE Submittals of Sept 15, 2017 and March 29, 2019) showed changes to the following parameters from the original permit application (See PSE Submittals of May 22, 2017 and June 22, 2017):

-Flare stack height increased to 105 feet
-Flare inside diameter decreased to 6 feet at the exit.
-H2S inlet concentrations updated by CB&I with more accurate engineering estimates as well as information associated with the Williams pipeline tariffs to refine the original assumptions.

These changes are expected to reduce impacts from the facility.

During PSCAA's review of the NOC permit application, the agency determined that an analysis of greenhouse gas (GHG) emissions and impacts in the Final Environmental Impact Statement (FEIS) issued by the City of Tacoma on November 9, 2015 included quantitative emissions for the Tacoma LNG facility site, but did not account for "upstream" GHG emissions associated with natural gas extraction and transmission. In addition, PSCAA determined that the Washington State Department of Ecology guidance document for identification and evaluation of GHGs, which the FEIS relied upon, had been withdrawn for revision after the completion of the FEIS. Accordingly, the Agency prepared a Supplemental Environmental Impact Statement (SEIS). The SEIS only addresses life cycle greenhouse gas emissions and supplements the Air and Cumulative Impacts sections of the City of Tacoma's FEIS. The Agency is relying on the FEIS for all other aspects of the SEPA review.

The Agency hired a consultant (Ecology in Environment) to help prepare the SEIS. A Draft SEIS, including a quantitative analysis of GHG emissions based on a life cycle analysis, was published October 8, 2018 for public comment. The public comment period (October 8th through November 21st, 2018) included a public hearing in Tacoma on October 30, 2018.

On March 29, 2019, the Agency published the Final SEIS (FSEIS) for the life cycle GHG analysis. As part of the SEIS public process, PSCAA solicited and received approximately 14,820 comment submittals. They were categorized into the following broad issue categories:

-General Opposition to the project.
-General support for the project.
-Comments outside of the scope of the SEIS.
-Determination of the SEIS scope.
-Language used in the SEIS.
-GHG life-cycle methodology, calculations and the inputs and assumptions.

-SEIS purpose and need.
-Regulatory framework.
-SEPA alternatives analyzed.

All comments were carefully considered, and the Agency made certain changes to the SEIS in response to those comments as well as providing written responses to all comments. These responses are in Appendix C of the final SEIS. (See link below). The final SEIS and supporting documentation is posted on the Agency website at:
www.pscleanair.org/PSELNGPermit

Based on the analysis presented in the SEIS (see SEIS, Executive Summary, ES. 4 Major Conclusions, p.3, March 29, 2019), the following major conclusions were drawn:

-The use of LNG produced by the Proposed Action, instead of petroleum based fuels for marine vessels, trucks, and peak shaving was predicted to result in an overall decrease in GHG Emissions, a net beneficial impact compared to the No Action Alternative.

-The conclusions regarding the overall reductions in GHG emissions stated above is dependent upon the assumption that the sole source of natural gas supply to the facility is from British Columbia or Alberta Canada, but entering Washington through British Columbia. The SEIS analysis supports the recommendation that the facility's air permit (this NOCOA), if approved, include the condition that the sole source of the natural gas be British Columbia or Alberta. As a condition of the permit, if approved, this requirement is enforceable by the Agency.

-The SEIS analysis demonstrates that GHG emissions are predicted to result in an overall decrease with the completion of the Proposed Action as conditioned above. This means that the Proposed Action will not cause a significant adverse impact from GHG emissions. In addition, if different assumptions in the life-cycle analysis were to change the final comparative amounts of emissions (e.g. to go from a small decrease to a small increase in GHG emissions as described in Section 4.5 and 4.8 of the SEIS), a small increase in GHG emissions would still not be considered a significant adverse impact because the increase would be small compared to the total GHG emission identified in the life-cycle analysis. Under this latter scenario, the Proposed Action would still need the condition that the sole source of the natural gas supplied to the facility is be British Columbia or Alberta.

[SEIS Issued by This Agency, March 29, 2019]
[See also SEIS, Section 4.5, Summary of Impacts, "Discussion of life cycle analysis and source of gas", p.4-10 and p.4-11]

Based on the above[1] and pursuant to the State Environmental Policy Act, RCW 43.21C.060, WAC 197-11-660, and Puget Sound Clean Air Agency Regulation I, Section 2.12, the following condition is included in the draft permit as a result of the SEIS analysis:

[1] This condition generally described herein has been voluntarily accepted by PSE (the applicant) (See PSE letter dated November 21, 2018, Comments on Tacoma LNG Project Draft Supplemental Environmental Impact Statement, Comment #1, p.2)

Pursuant to the State Environmental Policy Act, RCW 43.21C.060, WAC 197-11-660, and Puget Sound Clean Air Agency Regulation I, Section 2.12:

The owner and/or operator shall ensure that the sole source of natural gas supply used in all operations at the Tacoma LNG facility comes from British Columbia or Alberta, Canada. Compliance with this condition shall be verified by the owner and/or operator maintaining the following records:

a. *Monthly records documenting the purchase of natural gas from seller(s) at the Huntingdon, B.C. Pool (trading hub) showing delivery point of the Huntingdon/Sumas interconnect with Northwest Pipeline and the corresponding monthly volume purchased.*
b. *Monthly records of nominations on Northwest Pipeline contracts showing receipt point of Sumas, delivery point of Frederickson and monthly volume of natural gas delivered.*
c. *Monthly records of nominations on the PSE system showing receipt point of Fredrickson, delivery point of Tacoma LNG facility and monthly volume of natural gas delivered.*
d. *Monthly records documenting the volume of natural gas received at the Tacoma LNG facility*
e. *Monthly records indicating that the flow of Natural Gas from Canada was from north to south passed the Fredrickson Gate Station.*
f. *In the event that the natural gas pipeline supplying the Tacoma LNG facility ceases to transport gas from north to south passed the Fredrickson Gate Station, the owner and/or operator shall immediately cease accepting natural gas from the pipeline.*
    i. *If the event described in Condition #40(f) of this order occurs, the owner and/or operator shall submit a report to the Agency no later than 15 days after original discovery outlining all of the following:*
        1. *Date and Time of incident.*
        2. *Owner and/or operators response to the incident.*
        3. *If the natural gas continued to be accepted during the event, provide reason(s) operations continued pulling natural gas from the pipeline.*
        4. *Measures taken to minimize the amount of natural gas taken from the pipeline during this time.*
        5. *Quantity of natural gas processed during the event.*
g. *The owner and/or operator shall submit semiannual data reports to the Agency compiling and summarizing the data recorded in Conditions #40 (a) – (f) of this order. These semiannual reports shall be submitted no later than January 31 and July 31 for each proceeding six month calendar period. If the issuance of this permit causes one of these reporting periods to be shorter than 6 months, the owner and/or operator shall submit data for the number of months it was operating before January 31 or July 31.*

No further review was conducted for SEPA.

E. BACT REVIEW

<u>Regulatory Background:</u>

WAC 173-400-113 states that a permitting authority that is reviewing an application to establish a new source or modification in an attainment or unclassifiable area shall issue an order of approval if it determines that the proposed project satisfies "*The proposed new source or modification will employ BACT for all pollutants not previously emitted or whose emissions would increase as a result of the new* *source or modification*." This BACT (defined below) requirement applies to this facility since this is a new source.

Washington State regulation, WAC 173-400-030, defines **Best available control technology (BACT)** as an emission limitation based on the maximum degree of reduction for each air pollutant subject to regulation under chapter 70.94 RCW emitted from or which result from any new or modified stationary source, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of the "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard under 40 C.F.R. Part 60 and Part 61. Emissions from any source utilizing clean fuels, or any other means, to comply with this paragraph shall not be allowed to increase above levels that would have been required under the definition of BACT in the Federal Clean Air Act as it existed prior to enactment of the Clean Air Act Amendments of 1990.

Analysis:
The purpose of the BACT review is to demonstrate that PSE LNG will implement limitations or reductions for all increases in emissions that are not exempt under Reg 1 Section 6.03 (c). For this permitting action, the proposed LNG vaporizer rated at 66 MMBtu/hr, and the enclosed ground flare used to combust waste gas will have emissions of greenhouse gases, carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM), volatile organic compounds (VOCs) or toxic air pollutants (TAPs).
The equipment leaks from flanges, seals, and pipes will have emissions of greenhouse gases, and volatile organic compounds (VOCs) and toxic air pollutants (TAPs).

Recently issued BACT determinations from EPA's BACT Clearinghouse, California's Air Resources Board BACT Clearinghouse, Sacramento Metropolitan Air Quality Management District (SMAQMD), Bay Area Air Quality Management District (BAAQMD), South Coast Air Quality Management District (SCAQMD) and Texas Commission on Environment Quality (TCEQ) are presented below for initial comparison.

Vaporizer (Natural Gas steam generating unit) less than 100 MMBtu/hr:

VOC BACT review for natural gas fired steam generating units (< 100 MMBtu/hr)

Origin	BACT Determinations
Bay Area Air Quality Management District (BAAQMD)	Good combustion practices and fuel selection
EPA RBLC ID TX-0751	4.0 ppmv @ 3% O_2 dry or 0.00170 lb/MMBtu
EPA RBLC ID WY-0075	0.00170 lb/MMBtu
EPA RBLC ID MD-0046	0.0020 lb/MMBtu
South Coast AQMD: http://www.aqmd.gov/docs/default-source/bact/laer-bact-determinations/aqmd-laer-	PPMVD@3%O2: NOx-5, CO-5, NH3-5. Averaging times: NOx measured by source test-1 hr, NOx measured by CEMS-24 hr, CO-1 hr, NH3-1 hr. RECLAIM NOx Major Source. PM limited to 0.01 gr/scf. SO2 limited to 0.2

bact/427061-aes-huntington-beach-rev.pdf?sfvrsn=4	lb/MMBtu heat input. Maximum lb/mo. based on fuel use: VOC-1354, PM10-1202. Maximum 374 lb/day CO. CEMS for NOx and CO. Periodic NH3 tests (quarterly first year, semi-annual second year, annual thereafter). Facility must report, quarterly, NOx and CO 1-hr exceedances and NOx 24-hr exceedances. Source Test results for this boiler were 4.2 ppmv VOC
Massachusetts – http://www.mass.gov/eea/docs/dep/air/approvals/opp/op/op-hopcolng.pdf **Four boilers (EU#6-9) to vaporize liquefied natural gas**	No standards for VOC
NC#11188	0.0050 lb/MMBtu
Most Stringent (ppmv)	**4.0 ppmv @ 3% O_2 dry (0.0017 lbs VOC/MMBtu)**

The Agency reviewed the VOC information presented above for BACT and determined that for this permitting case, 4.0 ppmv @ 3% O2 was considered most stringent and economically feasible.

NO_x BACT review for natural gas fired steam generating units (< 100 MMBtu/hr)

Origin	BACT Determinations
Bay Area Air Quality Management District (BAAQMD)	Low NOx burners and flue gas recirculation and Selective Catalytic Reduction (SCR)
Sacramento Metropolitan Air Quality Management District (SMAQMD)	Low NOx burners – 9.0 ppmv @ 3% O_2 dry
South Coast Air Quality Management District (SCAQMD) – Rule 11146.1	9.0 ppmv @ 3% O_2 dry or 0.0110 lb/MMBtu
SCAQMD BACT Guidelines < 20 MMBtu/hr	12.0 ppmv @ 3% O_2 dry
South Coast AQMD – Permit #F23622	Low NOx burners – 9.0 ppmv @ 3% O_2 dry 15 min average
South Coast AQMD – Permit #359772	SCR – 7.0 ppmv @ 3% O_2 dry 15 min average
Santa Barbara County APCD – Permit #11974	Low NOx burners – 9.0 ppmv @ 3% O_2 dry 6 min average
San Diego County APCD – Permit #2012-APP-002050	Low NOx burners – 9.0 ppmv @ 3% O_2 dry 60 min average
TCEQ	0.010 lb/MMBtu when firing 75% - 100% natural gas
EPA RBLC ID TX-0751	0.010 lb/MMBtu
EPA RBLC ID FL-0356	0.050 lb/MMBtu
EPA RBLC ID WY-0075	0.01750 lb/MMBtu

EPA RBLC ID MD-0046	0.010 lb/MMBtu
NC#11188	0.0110 lb/MMBtu
NC#10739, NC#10657 and NC#10659	9.0 ppmv @ 3% O_2 dry 60 min average
Massachusetts – http://www.mass.gov/eea/docs/dep/air/approvals/opp/op/op-hopcolng.pdf **Four boilers (EU#6-9) to vaporize liquefied natural gas**	Work Practices and Tune-ups
Most Stringent with SCR (ppmv)	**7.0 ppmv @ 3% O_2 dry (0.0085 lbs NO_x/MMBtu)**
Most Stringent without SCR (ppmv)	**9.0 ppmv @ 3% O_2 dry (0.010 lbs NO_x/MMBtu)**

The Agency reviewed the BACT information presented above for NOx and determined that for this permitting case, low-NO_x burners capable of meeting 9 ppm NOx at 3% O2 was most stringent and technologically feasible for a new natural gas fired heating unit that will only operate 10 days out of the year. SCR can achieve NO_x reduction efficiencies greater than 70% and get ppm standards as low as 7 ppm; however, SCR is not cost effective for this project since the NOx emissions are below major source thresholds and the heater is only operating 10 days out of the year. The cost per ton of NOx reduction was evaluated and submitted by PSE:


Attachment 1 Cost Analysis Spreadsheet


Attachment 2 Cost Analysis Spreadsheet

The cost per ton of reduction for the heater using SCR would be economically infeasible when operating at 10 days per year. The requirement to operate only 10 days per year will be placed in the permit.

CO BACT review for natural gas fired steam generating units (< 100 MMBtu/hr)

Origin	BACT Determinations
Bay Area Air Quality Management District (BAAQMD)	Good combustion practices and 50 ppmv @ 3% O_2 dry using BAAQMD Source Test Method ST-6 (average of three 30-minute sampling runs), or BAAQMD approved equivalent
SCAQMD BACT Guidelines < 20 MMBtu/hr firetube	50.0 ppmv @ 3% O_2 dry
SCAQMD – Permit #F23622	100.0 ppmv @ 3% O_2 dry 15 min average
SCAQMD – Permit #359772	50.0 ppmv @ 3% O_2 dry 15 min average
Santa Barbara County APCD – Permit #11974	50.0 ppmv @ 3% O_2 dry 6 min average
TCEQ	50.0 ppmv @ 3% O_2 dry
EPA RBLC ID TX-0751	50.0 ppmv @ 3% O_2 dry

EPA RBLC ID FL-0356	0.080 lb/MMBtu
EPA RBLC ID WY-0075	0.03750 lb/MMBtu
EPA RBLC ID MD-0046	0.080 lb/MMBtu
NC#11188	0.0360 lb/MMBtu
NC#10657 and NC#10659	50.0 ppmv @ 3% O_2 dry 60 min average
NC#10739	50.0 ppmv @ 3% O_2 dry 60 min average
Massachusetts – http://www.mass.gov/eea/docs/dep/air/approvals/opp/op/op-hopcolng.pdf **Four boilers (EU#6-9) to vaporize liquefied natural gas**	No standards for CO
Most Stringent (ppmv)	**50.0 ppmv @ 3% O_2 dry (0.037 lbs CO/MMBtu)**

The Agency reviewed the CO information presented above for BACT and determined that for this permitting case, 50ppmv @ 3% O2 was considered most stringent and technologically feasible for most new steam generating units permitted across the nation.

PM BACT review for natural gas fired steam generating units (< 100 MMBtu/hr)

Origin	BACT Determinations
TCEQ	< 5% opacity
EPA RBLC ID FL-0356	< 10% opacity
EPA RBLC ID WY-0075	0.01750 lb/MMBtu
EPA RBLC ID MD-0046	0.00750 lb/MMBtu with no visible emissions
EPA RBLC IL – 0129	0.00750 lbs/MMBtu
San Joaquin Valley APCD – Permit # S3412120	0.0070 lb/MMBtu
Bay Area Air Quality Management District (BAAQMD)	Good combustion practices and fuel selection
NC#10739	≤ 5% opacity
Massachusetts – http://www.mass.gov/eea/docs/dep/air/approvals/opp/op/op-hopcolng.pdf **Four boilers (EU#6-9) to vaporize liquefied natural gas**	≤ 0.015 lbs/MMBtu
Most Stringent (opacity)	**No Visible Emissions and ≤ 0.0075 lbs/MMbtu**

The Agency reviewed the PM information presented above for BACT and determined that for this permitting case, the most stringent BACT in the RBLC is 0.00750 lb PM/MMbtu and no visible emissions. The more stringent BACT from San Joaquin Valley was 0.0070 lbs/MMBtu which was the only standard found this low and was for much higher emissions than the Tacoma LNG PM emissions. Burning natural gas should not have substantial PM emissions and no visible emissions and 0.0075 lbs/MMbtu is consistent with other recently issued BACT for steam generating units and control devices.

SOx BACT review for natural gas fired steam generating units (<100 MMbtu/hr)

Origin	BACT Determinations
TCEQ	No standard (Good combustion Practices)
Bay Area Air Quality Management District (BAAQMD)	Fuel selection Natural Gas or Treated Refinery Gas Fuel w/ <0.50 ppmv Hydrogen Sulfide and <100 ppmv Total Reduced Sulfur Good Combustion Practices
Most Stringent (SOx)	**Burn Natural Gas with Good Combustion Practices**

The Agency reviewed the SOx information presented above for BACT and determined that for this permitting case, good combustion practices and the use of natural gas from the vaporizer would be considered BACT for SOx. This is consistent with other recently issued BACT for steam generating units and control devices that the agency has issued.

Enclosed ground flares:

Most agency websites did not contain information for enclosed ground flares specific to natural gas feed gas leaks or heavy hydrocarbon waste. Ground flares are typically custom-designed, based on a given facility’s waste gas composition and flow rate; therefore, a direct comparison of BACT/LAER determinations for facility types that have different inlet gas composition and flow characteristics is sometimes not appropriate. The LNG Facility’s waste gas can range from very cold (e.g. cryogenic LNG vapors) or warm (liquefaction and pretreatment off gas). All of these factors influence the selection of burner technology for the LNG Facility’s proposed ground flare. Four burner types are required to address the wide flow, heat input and inlet temperature variation experienced by the LNG Facility. PSE proposes the following 4-burner scenario to address the ground flare’s wide operating ranges:

- A large low-NOx burner will be used during periods when the inlet waste gas stream is warm and has a heat input rate greater than 8 MMBtu/hr (Burner 1)
- A small cryogenic burner will be used to flare loading arm/hose purge gas after ship bunkering or truck loading. (Burner 2)
- A small standard burner will be used during warm, low flow inlet gas cases that occur rarely during holding mode or facility turndown (Burner 3)
- A large low-NOx burner designed for cold inlet gases will be used during plant upset conditions. (Burner 4)

A review was conducted for various types of operations that do not match exactly what Tacoma LNG will be doing with their flares but they are included for informational and comparison purposes since flaring technology is not uncommon

Origin	Process Source	BACT Determination
BAAQMD	Catalyst Regeneration for Heavy Hydrocarbon Removal	Enclosed flare or afterburner w/ >0.3 sec. retention time at >1400 F
SJVAPCD	Auxiliary Burner System, Dryer, Natural gas fired <20 MMbtu/hr	▪ 9.0 ppmv @3% O2 NOx (low temperature oxidization, SCR, or equal) ▪ 15 ppmv @3% O2 NOx (Low NOx burner, or equal) ▪ 20 ppmv @3% O2 NOx (Low NOx burner, or equal)
TCEQ	Flares/ Vapor Combustors	Destruction Efficiency: 99% for certain compounds up to three carbons, 98% otherwise No flaring of halogenated compounds allowed Flow monitor will be required. Composition or BTU analyzer may be required. Flare required to meet 40 CFR 60.18 Vapor Combustor 99% control efficiency, monitoring temperature and initial performance test.
MassDep	Flares with biomass digester gas for fuel	▪ NO_x – 2.70 lbs per Mscf/min gas flared ▪ CO – 13.70 lbs per Mscf/min gas flared ▪ PM – 0.15 lbs per Mscf/min gas flared ▪ CO_2 – 7,105 lbs per Mscf/min gas flared ▪ VOC – 0.55 lbs per Mscf/min gas flared ▪ SO_2 – 99.5 percent oxidation of 200 ppm H_2S inlet emissions ▪ H_2S – 200 ppm inlet concentration
SCAQMD (No. 538706)	Flare for oil and gas operations	▪ VOC – 10 ppmv on a dry, volumetric basis corrected to 3% oxygen (O_2) ▪ NO_x - 15 ppmv on a dry, volumetric basis corrected to 3% oxygen (O_2)

Origin	Process Source	BACT Determination
		▪ CO - 10 ppmv on a dry, volumetric basis corrected to 3% oxygen (O_2)
SCAQMD (No. 245157)	Flare for landfill operations	▪ Minimum temperature in flare stack: 1400 °F ▪ NOx 0.06 lbs/MMBtu ▪ CO 0.01 lbs/MMBtu ▪ PM 6.1 lbs/MMscf ▪ Minimum non-methane organic compounds (NMHC) destruction efficiency of 98% or maximum NMHC concentration in stack of 20 ppm, dry corrected to 3% O2 as hexane
MaineDep (A-1086-71-A-N)	Flare with biomass digester gas for fuel	▪ NO_x – 48.0 lbs per MMscf gas flared ▪ CO – 1.8 lbs per MMscf gas flared ▪ PM – 0.02 lbs/MMBtu ▪ VOC – 12.10 lbs per MMscf gas flared ▪ SO_2 – 2.0 lbs per MMscf gas flared ▪ Opacity – visible emissions from the flare shall not exceed 10% on a 6 minute block average basis, except for no more than one (1) six (6) minute block average in a 3 hour period
NC 11073 – King County Solid Waste Division	Enclosed Ground Flare for landfill gas	▪ Reduce NMOC by 98% by weight or reduce emissions to 20 ppm by volume hexane ▪ Flare shall be designed for and operated with no visible emissions as determined by EPA method 22, except for periods not to exceed a total of 5 minutes during any consecutive 2 hours.
NC 11399 Seattle Solid Waste Utilities Kent Highlands Landfill	Enclosed Ground Flare for landfill gas	▪ Reduce NMOC by 98% by weight or reduce emissions to 20 ppm by volume hexane dry @ 3% O_2
NC 11400 – Seattle Solid Waste Utility Midway	Enclosed Ground Flare for landfill gas	▪ Reduce NMOC by 98% by weight or reduce emissions to 20 ppm by volume hexane dry @ 3% O_2
SJVAPCD	Flare with biomass digester gas for fuel	▪ NO_x 0.06 lbs/MMBtu ▪ ≤ 40 ppmv Sulfur in digester gas

PSE submitted their own BACT analysis for the enclosed ground flare and requested the following limits in the supplemental application submitted 3/29/19:

GROUND FLARE

PSE's proposed BACT for the flare exhaust remains consistent with the most restrictive determinations for enclosed ground flares. The proposed technology and BACT emission limits are presented in Table C-2.

Table C-2: Proposed BACT for the Flare

Pollutant	Control Technology	BACT Limit
NO_x	Good Combustion Practices/Low NO_x Burners	0.06 lb/MMBtu
CO	Good Combustion Practices	0.2 lb/MMBtu
PM, PM_{10}, $PM_{2.5}$	Good Combustion Practices	0.0075 lb/MMBtu
VOCs	Good Combustion Practices	Flare designed to achieve a destruction efficiency of at least 99% for compounds up to 3 carbons.
SO_2	Good Combustion Practices	165 lb/MMscf
TAPs	Good Combustion Practices	0.37 lb/MMBtu

The Agency reviewed the proposal and determined that the proposed BACT for the flares were acceptable, taking into consideration energy, environmental, economic impacts and a comparison to other BACT analysis done (outlined above) for each pollutant. PSE indicated that there were modifications to their table above for the NOx and CO limits per burner. The two large burners will have a NOx limit set at 0.025 lbs/MMBtu, the small cold burner will have a limit of 0.060 lbs/MMBtu, and the small warm burner will have a limit of 0.066 lbs/MMbtu:

- 0.066 lbs/MMBtu whenever the small warm burner is operating (Burner 3)
- 0.060 lbs/MMBtu whenever the small cold burner is operating (Burner 2)
- 0.023 lbs/MMBtu whenever exclusively one or both large burners are operating (Burners 1 and 4)

The large burners have Low NOx burners, whereas fitting the small burners with low NOx burners was not technically feasible. The two small burners are also planned to rarely be operated (see waste gas case scenarios).

The two large burners will have a CO limit set at 0.075 lbs/MMBtu, the small cold burner will have a limit of 0.180 lbs/MMBtu, and the small warm burner will have a limit of 0.196 lbs/MMbtu:

- 0.196 lbs/MMBtu whenever the small warm burner is operating (Burner 3)
- 0.180 lbs/MMBtu whenever the small cold burner is operating (Burner 2)
- 0.075 lbs/MMBtu whenever exclusively one or both large burners are operating (Burners 1 and 4)

As mentioned previously, each flare is designed to operate specific to the facility for which it is being used. The processes evaluated above are mostly for flares used in landfill operations or for the oil and gas industry which would have a different burner design for the higher carbon molecules being flared. An analysis was done below to show the differences in gases from Tacoma LNG to landfill gas, Digester gas, and a special analysis from an oil refinery in California (Linn Operating in South Coast Air Quality Management District):

Waste (Inlet) Composition (mole %)	***All Flare Case - Min/Max*** Min	Max	Median Average*	**Landfill Gas Composition (typical range, CARB)**	**Digester Gas Composition (typical range, CARB)**	**Oil and Gas Field Composition (Linn Operating SCAQMD)**
Nitrogen – N2	0.0	78.0	5.0	0.6 - 46	0.1 - 3	9.04
Methane – CH4	9.2	88.0	37.6	20 - 60	56 - 65	68.28
Ethane – C2H6	0.0	20.4	2.3	0	0	5.62
Ethylene – C2H4	0.0	3.2	0.1	NS	NS	
Propane – C3H8	0.0	20.2	2.5	0	0	4.83
Butane – n-C4H10	0.0	13.2	0.5	0	0	1.9
n-Pentane – C5H12	0.0	2.9	1.0	NS	NS	0.25
n-Hexane – C6H14	0.0	0.6	0.0	NS	NS	0.18
Carbon Dioxide – CO2	0.0	69.4	0.2	22 - 60	35 - 40	7.98
Water – H2O	0.0	7.6	0.0	NS	NS	0.1
Hydrogen Sulfide – H2S	0.0	0.1	0.0	Tr.	Tr.	
Heating Value (BTU/scf)	200	1,675	764.0	208 - 600	550 - 646	1055

This analysis shows some examples of the differences in composition between the natural gas used on the PSE site, compared to landfill gas (Taken from California Air Resource Board's website), digester gas (CARB), and the oil industry (SCAQMD).

In regards to SO_2, only one permit was found that limited SO_2 to 2.0 lbs per MMscf burned (Maine DEP), which is used to burn Biomass which is not the same as pipeline natural gas. PSE submitted information on the amount of sulfur in the gas (taken from William northwest pipeline) which is shown below:

		Three Tests						Wt.% of total excluding nondetects
Carbon Disulfide	ppbv	<	20 c	<	20	<	20	
	µg/m3	<	62.3	<	62.3	<	62.3	
Carbonyl Sulfide	ppbv	<	20	<	20	<	20	
	µg/m3	<	49.1	<	49.1	<	49.1	
Dimethyl Disulfide	ppbv	<	20	<	20	<	20	
	µg/m3	<	76.9	<	76.9	<	76.9	
Dimethyl Sulfide	ppbv		155		259		167	
	µg/m3		394		657		425	5%
Ethyl Mercaptan	ppbv		1330		3080		3270	
	µg/m3		3380		7820		8310	59%
Hydrogen Sulfide	ppbv	<	20	<	20	<	20	
	µg/m3	<	27.2	<	27.2	<	27.2	
Isobutyl Mercaptan	ppbv	<	20	<	20	<	20	
	µg/m3	<	73.6	<	73.6	<	73.6	
Isopropyl Mercaptan	ppbv		805		1460		1500	
	µg/m3		2500		4520		4680	37%
Methyl Mercaptan	ppbv	<	20	<	20	<	20	
	µg/m3	<	39.3	<	39.3	<	39.3	
n-Butyl Mercaptan	ppbv	<	20	<	20	<	20	
	µg/m3	<	73.8	<	73.8	<	73.8	
n-Propyl Mercaptan	ppbv	<	20	<	20	<	20	
	µg/m3	<	62.2	<	62.2	<	62.2	
t-Butyl Mercaptan	ppbv	<	20	<	20	<	20	
	µg/m3	<	73.6	<	73.6	<	73.6	
Total Sulfur detected	ppbv		2290		4790		4940	

This shows that the total amount of sulfur compounds in the natural gas. PSE's proposed SO_2 standard of 165 lbs of SO_2 per MMScf (0.16 lbs of SO_2/MMBtu) was lower than the most stringent SO_2 Standard shown above from Maine DEP.

Fugitive emissions equipment leaks:

A review was done of other agency websites for similar facilities as natural gas processing plants and/or oil refineries for comparison in fugitive emission equipment leaks. If the agency website had determinations for an oil refinery, it was also included in the analysis below for fugitive equipment leaks for comparison purposes.

Origin	Process Source	BACT Determination
SJVAPCD	Natural Gas Processing Plant – Valves, Connectors, and Compressors and Pump Seals (subject to Rule 4403)	Leak defined as a dripping rate of more than three (3) drops per minute of liquid containing VOC or as a reading of methane, in excess of • 100 ppmv above background (for Valves and Connectors) and • 500 ppmv (for Compressor and Pump Seals) when measured per EPA Method 21 from the potential source, and an Inspection and Maintenance Program pursuant to District Rule 4409. Or Leak defined as a dripping rate of more than three (3) drops per minute of liquid containing VOC or as a reading of methane, in excess of 5,000 ppmv above background when measured EPA Method 21, for all components, and an Inspection and Maintenance Program pursuant to District Rule 4409.
TCEQ	Equipment Fugitive Leaks	Uncontrolled VOC emissions < 10 tpy - None 10 tpy < uncontrolled VOC emissions < 25 tpy - 28M leak detection and repair program with 75% credit for 28M Uncontrolled VOC emissions > 25 tpy - 28VHP leak detection and repair program with 97% credit for valves, 85% for pumps and compressors VOC vp < 0.002 psia - No inspection required Approved odorous compounds: NH3, C12, H2S, etc. - Audio/Visual/Olfactory (AVO) inspection twice per shift with Appropriate credit for AVO program

Origin	Process Source	BACT Determination
Santa Barbara County Air Pollution and Control District	Oil and Gas Fugitive Hydrocarbon Components	https://www.ourair.org/wp-content/uploads/BACT-Guideline-1.2.pdf Valves, Flanges, Pump Seals, Compressor Seals (reciprocating drives and rotary drives), Pressure Relief valves/devices (PRD), and all other welded components must meet an LDAR of 100 ppmv or less.

Typical BACT determinations for significant fugitive emissions include the use of a Leak Detection and Repair Program (LDAR).

LDAR programs are used to inspect fugitive components to identify leaks either by using instruments or by physical inspections. Leaks identified by the inspections are then repaired within a specified time period which helps reduce emissions. LDAR emission reduction credits can be used, and is explained in more detail in the emission calculation section of this worksheet.

Instrument Monitoring LDAR programs can typically be differentiated by four key criteria:

- Leak definition: The leak definition is the monitored concentration of an air contaminant, defined in parts per million by volume (ppmv), that identifies a leaking component needing repair.
- Monitoring frequency: The monitoring frequency varies depending on the component types and the LDAR program in place.
- Properties of the monitored compounds: Some LDAR programs define the components to be monitored by the vapor pressure of the material in the component or the weight percent of VOC in the stream.
- Requirements for repair: Program repair requirements may be either directed or non-directed maintenance. A directed maintenance program requires that a gas analyzer be used in conjunction with the repair or maintenance of leaking components to assure that a minimum leak concentration is achieved. A non-directed maintenance program does not require the use of a gas analyzer during repair or maintenance of a leaking component.

There are a number of federal regulations which exist to address VOC equipment leaks. A list of the federal regulations which have some form of leak detection program is shown below for informational purposes:

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New Source Performance Standards (NSPS) (40 CFR Part 60)

Subpart	Title
VV	Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006.
VVa	Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.
XX	Standards of Performance for Bulk Gasoline Terminals.
DDD	Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry.
GGG	Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006 (Excluding Those Subject to Subparts VV or KKK).
GGGa	Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.
KKK	Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011 (Excluding Those Covered Under Subparts VV or GGG). (Replaced by Subpart OOOO for facilities modified after August 23, 2011).
QQQ	Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems.
OOOO	Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015.
OOOOa	Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced After September 18, 2015.

National Emission Standards for Hazardous Air Pollutants (NESHAP) for Source Categories, Maximum Achievable Control Technology (MACT) (40 CFR Part 63)

Subpart	Title
H	National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks.
I	National Emission Standards for Organic Hazardous Air Pollutants for Certain Processes Subject to the Negotiated Regulation for Equipment Leaks. Rubber Production, Agricultural Chemicals, Polymers/Resins.
J	National Emission Standards for Organic Hazardous Air Pollutants for Polyvinyl Chloride and Copolymers Production.
R	National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations).
S	National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry
U	National Emission Standards for Hazardous Air Pollutants Emissions: Group I Polymers and Resins.
W	National Emission Standards for Hazardous Air Pollutants for Epoxy Resins Production and Non Nylon Polyamides Production.
Y	National Emission Standards for Marine Tank Vessel Loading Operations.
CC	National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.
DD	National Emission Standards for Hazardous Air Pollutants from Off Site Waste and Recovery Operations
GG	National Emission Standards for Aerospace Manufacturing and Rework Facilities
HH	Oil and Natural Gas Production Facilities.
PP	National Emission Standards for Containers
QQ	National Emission Standards for Surface Impoundments
SS	National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process.
TT	National Emission Standards for Equipment Leaks Control Level 1.
UU	National Emission Standards for Equipment Leaks Control Level 2 Standards.
YY	National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards.
III	National Emission Standards for Hazardous Air Pollutants for Flexible Polyurethane Foam Production.
JJJ	National Emission Standards for Hazardous Air Pollutant Emissions: Group IV Polymers and Resins.
MMM	National Emission Standards for Hazardous Air Pollutants for Pesticide Active Ingredient Production.
OOO	National Emission Standards for Hazardous Air Pollutant Emissions: Manufacture of Amino/Phenolic Resins.
PPP	National Emission Standards for Hazardous Air Pollutant Emissions for Polyether Polyols Production.

Subpart	Title
VVV	National Emission Standards for Hazardous Air Pollutants: Publicly Owned Treatment Works
EEEE	National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non Gasoline)
FFFF	National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing.
BBBBB	National Emission Standards for Hazardous Air Pollutants for Semiconductor Manufacturing
GGGGG	National Emission Standards for Hazardous Air Pollutants: Site Remediation
HHHHH	National Emission Standards for Hazardous Air Pollutants: Miscellaneous Coating Manufacturing.
BBBBBB	National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities.
VVVVVV	Hazardous Air Pollutants for Chemical Manufacturing Area Source
HHHHHH	National Emission Standards for Hazardous Air Pollutant Emissions for Polyvinyl Chloride and Copolymers Production.

This list is not an exhaustive list of all standards which have LDAR requirements. There are some standards in 40 CFR part 61 as well, but did not pertain to this project so they were not reviewed.

For information purposes, the Pulp and Paper Major Source NESHAP (Subpart S) has an LDAR requirement that consists of monthly visible inspections and annual Method 21 tests with readings of 500 ppmv above background constituting a leak. Under Subpart S, repairs must be completed within 15 calendar days unless repair is infeasible without a process shutdown, in which case the repair must be made before completion of the next shutdown. See 40 CFR 63.453(k) and 457(d).

Similarly, the Chemical Manufacturing Area Source NESHAP (Subpart VVVVVV) requires a quarterly visual, olfactory, auditory or Method 21 (500 ppmv) leak inspection (which method is the source's choice) with repairs required within 15 days, if possible. See 40 CFR 63.11495(a)(3) - (5).

40 CFR 63, Subpart H shares the same general requirements as Subparts S and VVVVVV. However, each of these federal regulations is customized to the particular type of source category it is regulating. The Tacoma LNG project is not subject to the requirements of any of the listed subparts above, so in order to adequately use one of them as BACT for fugitive emissions, it is necessary to identify the relevant elements of the rule for the LDAR program at Tacoma LNG.

PSE initially proposed to implement an LDAR program that will follow some of the requirements of 40 CFR 60 Subpart H, which was used as the closest surrogate to the operations at the Tacoma LNG plant. This subpart does not apply to PSE directly but was used as an outline to implement the LDAR program for BACT for VOCs.

Not all elements of Subpart H make sense to apply to Tacoma LNG. For example, under Subpart H, implementation for new sources is divided into two phases (II and III) for pumps in light liquid service and valves in gas/vapor service or light liquid service. For pumps, Subpart H defines a leak as 10,000 ppmv in Phase II and 1,000 ppmv in Phase III. For valves, a leak is defined as 500 ppmv in both Phase

II and III. Tacoma LNG will get a single definition of a leak (500 ppmv) that applies anywhere subject to LDAR.
Tacoma LNG will be required to submit a written LDAR program for PSCAA's review and approval no later than 45 days before startup. Upon startup, Tacoma LNG would implement the program as submitted, if not yet approved. Upon approval by PSCAA, Tacoma LNG will implement the approved LDAR program. The mandatory requirements of the rule would be as follows:

- Monthly visual and Method 21 monitoring of equipment

- Repair of any detected leaks (>500 ppm over background) within 15 calendar days (subject to delay of repair provisions equivalent to those in 40 CFR 63.171).

- After 1 year of operation, Tacoma LNG may choose to reduce monitoring frequency if leak rates over the prior 12 months have been as follows:
    - If the overall unit equipment leak rate is 2% or greater, the facility shall monitor monthly.
    - For valves only, if the leak rate is 2% or greater the facility may choose to monitor quarterly and implement an alternative monitoring plan equivalent to 40 CFR 63.175(d) or (e).
    - If the overall unit equipment leak rate is < 2%, the facility may monitor quarterly.
    - If the overall unit equipment leak rate < 1%, the facility may monitor semiannually
    - If the overall unit equipment leak rate < 0.5%, the facility may monitor annually

- Equipment that are difficult to monitor may be monitored annually instead of the above schedule if the following conditions are met:
    - The equipment cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface or it is not accessible at any time in a safe manner; and
    - The total number of such equipment does not exceed 3 percent of the total equipment at the source.

- If, after one year of operation, on a 6-month rolling average, the greater of 10 percent of the total pumps in liquid or gas service or 3 pumps in liquid or gas service leak are determined to leak, a quality improvement plan to reduce leakage below this threshold.

- Recordkeeping consisting of:
    - List of all equipment subject to this LDAR program with identification of any equipment deemed difficult to monitor.
    - Records documenting all visual and Method 21 inspections taken pursuant to this LDAR program.
    - Date a leak was first detected and date of repair.
    - Reason for delay if not repaired within 15 days

- The LDAR program applies only to valves, pressure release valves, flanges, connectors, pump seals, compressor seals and swivel joints in active liquid or gas service and under positive pressure and that are intended to operate in organic service 300 hours or more during the calendar year.

The elements from Subpart H that are not identified above either relate to equipment not in use at Tacoma LNG or relate to initial phases of the program that are not proposed for incorporation into Tacoma LNG's LDAR program.

Recommendations:

Natural gas vaporizer

The Agency reviewed the other BACT determinations above for the 66 MMbtu/hr vaporizer and determined that for this permitting case, the emissions limitations presented in the table below results in the maximum technically and economically feasible reduction compliant with BACT regulations:

Pollutant	BACT Limit
SO_2	Good combustion practices burning only natural gas
VOCs	4.0 ppmv @ 3% O_2 dry 60 min average
CO	50.0 ppmv @ 3% O_2 dry 60 min average
NO_x	9.0 ppmv @ 3% O_2 dry 60 min average when firing natural gas
PM	No visible emissions

Enclosed ground flare:

The Agency reviewed the other BACT determinations above for the enclosed ground flare and determined that for this permitting case, the emissions limitations presented in the table below results in the maximum technically and economically feasible reduction compliant with BACT regulations. PSE's proposed VOC destruction is 99% for compounds up to 3 carbons.

Pollutant	BACT Limitation	BACT Compliance Demonstration
VOC	A minimum destruction efficiency of 99% of compounds up to 3 carbons or an outlet concentration of 10 ppmv	▪ Vent the following processes to a flare that meets the minimum NMOC destruction efficiency or NMOC outlet concentration: Feed Gas compressor, Amine Unit, Heavies storage and fuel system and liquefaction compressor. ▪ Initial and ongoing compliance testing using Puget Sound Clean Air Agency and EPA approved test methods. Compliance testing must be conducted for each pollutant annually and must consist of at least three separate test runs, each with a minimum duration of 30-minutes
SO_2	0.003 lbs/MMBtu (sulfur testing)	
NO_x	0.066 lbs/MMBtu (Small warm Burner) 0.060 lbs/MMBtu(Small cold burner) 0.025 lbs/MMBtu (Two Large Burners)	
CO	0.196 lbs/MMbtu (Small warm burner) 0.180 lbs/MMBtu(Small cold burner) 0.075 lbs/MMBtu(Two Large Burners)	
PM	0.0075 lbs/MMBtu	

The CO value is higher than the most stringent value found when doing research around enclosed flare BACTs; However, CO and NOx are interchangeable within a combustion system. PSE has decreased NOx to 0.066 lbs/MMBtu for the small burners and even further agreed to lower the large burners to 0.025 lbs/MMBtu, which requires CO to be, increased accordingly (0.196 lbs/MMBtu for the Small warm burner, and 0.075 lbs/MMBtu for the two large burners). The large burners are operated more frequently than the small burners as well. It is preferable to reduce NOx over CO in an interchangeable system due to the fact that NOx has a lower National Ambient Air Quality Standards (NAAQS) than CO:

Pollutant [links to historical tables of NAAQS reviews]	Primary/ Secondary	Averaging Time	Level	Form
Carbon Monoxide (CO)	primary	8 hours	9 ppm	Not to be exceeded more than once per year
		1 hour	35 ppm	
Nitrogen Dioxide (NO_2)	primary	1 hour	100 ppb	98th percentile of 1-hour daily maximum concentrations, averaged over 3 years
	primary and secondary	1 year	53 ppb [2]	Annual Mean

Equipment Leaks:

AS discussed above regarding fugitive equipment leaks, BACT for flanges/pipes/seals/etc for leaks will be the implementation of an LDAR program. This program will address leaks in a timely manner to reduce VOC or TAP emissions. The LDAR will be implemented from selected requirements found in 40 CFR 63 Subpart H, identified below:

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Section by Section Analysis of Incorporation of Subpart H into PSE LDAR Program

Rule	Summary	Relation to PSE LDAR Program
63.160	Applicability	NA
63.161	Definitions	Incorporated where relevant
63.162(a)	Determination of compliance	Incorporated
63.162(b)	Alternative limits	Not incorporated
63.162(c)	Equipment identification	Incorporated
63.162(d)	Vacuum service excluded	Incorporated
63.162(e)	<300 hrs excluded	Incorporated
63.162(f)	Leak tagging	Not incorporated as leak repair requirements cover need
63.162(g)	Calendar periods	Incorporated
63.162(h)	Requirement to fix leak	Incorporated
63.163(a)	Phase-in of requirements	Not incorporated--PSE adopting more stringent requirement
63.163(b)	Definition of leak	Not incorporated--PSE adopting more stringent requirement
63.163(c)	Repair within 15 days	Incorporated
63.163(d)	Calculation of percent leaking pumps	Incorporated
63.163(e)	Exemption for dual mechanical seal system	Incorporated
63.163(f)	Exemption for certain design	Incorporated
63.163(g)	Exemption for certain design	Incorporated
63.163(h)	Unmanned plant exemption	Not incorporated because not relevant
63.163(i)	90% exemption	Incorporated
63.163(j)	Unsafe-to-monitor exemption	Incorporated
63.164(a) - (f)	Seal system required to have a barrier fluid design	Not incorporated as addressed through leak testing
63.164(g)	Repair leaks within 15 days	Incorporated
63.164(h)	Exemption for certain design	Incorporated
63.164(i)	Exemption for certain design	Incorporated
63.165(a)	500 ppm leak threshold	Incorporated
63.165(b)	Repair within 5 days	Not incorporated as 15 day repair period is applied throughout facility consistent with other LDAR standards
63.165(c)	Exemption for certain design	Incorporated
63.165(d)	Exemption for certain design	Incorporated
63.166	Sampling connection systems	Not incorporated because not relevant
63.167	Open ended valves or lines	Not incorporated as leak repair standard is applied throughout facility consistent with other LDAR standards
63.168(a)	Phase-in of requirements	Not incorporated--PSE adopting more stringent requirement
63.168(b)	Definition of leak	Incorporated to the extent that PSE defines leak as 500 ppm or more from outset
63.168(c)	Phase I and II quarterly inspections	Not incorporated--PSE adopting more stringent requirement
63.168(d)	Phase III inspections	Partially incorporated--PSE adopting consistent tiered inspection timing facility-wide
63.168(e)	Computation of percent of leaking valves	Incorporated
63.168(f)	Repair deadlines	Partially incorporated--15 day repair period is applied throughout facility consistent with other LDAR standards
63.168(g)	First attempt examples	Incorporated
63.168(h)	Unsafe-to-monitor exemption	Incorporated

Rule	Summary	Relation to PSE LDAR Program
63.168(i)	Difficult-to-monitor exemption	Incorporated
63.168(j)	Valve count exemption	Incorporated
63.170	Surge control vessels	Not incorporated
63.171	Delay of repair	Incorporated
63.172	Closed-vent systems and control devices	Not incorporated--process not used
63.173	Agitators	Not incorporated--process not used
63.174(a)	Connector monitoring	Incorporated
63.174(b)	Monitoring interval	Incorporated
63.174(c)	Return to service	Incorporated
63.174(d)	Repair deadlines	Partially incorporated--15 day repair period is applied throughout facility consistent with other LDAR standards
63.174(f)	Unsafe-to-monitor exemption	Incorporated
63.174(g)	Unsafe-to-repair exemption	Incorporated
63.174(h)	Inaccessible/ceramic/ceramic lined exemption	Incorporated
63.174(i)	Percent leaking calculations	Incorporated
63.174(j)	Credit for removed connectors	Incorporated
63.175	Elective alternative quality improvement plan to allow less frequent monitoring	Incorporated other than election having to be made in first year of Phase III
63.176	Pump quality improvement plan	Incorporated
63.177	Alternative emission limitations: General	Not incorporated
63.178	Alternative emission limitations: Batch processes	Not incorporated
63.179	Alternative emission limitations: Closed vent processes	Not incorporated
63.180	Test methods	Incorporated
63.181	Recordkeeping requirements	Incorporate requirements to: • List all equipment subject to LDAR program, • maintain records of visual and Method 21 inspections, • maintain records when leak first detected, repair date and reason for delay if not repaired within 15 days, • maintain list of equipment in organic service <300hrs/yr • Maintain records for 2 years

An outline of the general LDAR program requirements is shown below:

- *Definitions under 40 CFR 63.16*
- *General requirements under 40 CFR 63.162(a), (c), (d), (f), (g), and (h)*
- *Monitoring provisions for equipment gas/vapor and light liquid service under 40 CFR 63.163 to 174, using the 500-ppm leak rate definition immediately upon startup*
- *Method 21 test methods and procedures (40 CFR part 60, Appendix A),*
- *Delay of repair provisions under 40 CFR 63.171*
- *The alternative quality improvement program for equipment described in 40 CFR 63.175 and 176, in lieu of related 40 CFR 63.168 and 163 requirements, upon written notification 30 days in advance and approval by PSCAA*
- *Recordkeeping provisions for equipment in VOC service under 40 CFR 63.181*
- *Records will be available for inspection by PSCAA.*

F. EMISSION ESTIMATES

The purpose of the emissions review is to identify the amounts of nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter (PM), sulfur dioxide (SO2), Carbon Dioxide (CO2), hazardous air pollutants (HAPs), and toxic air pollutants (TAPs) emitted from Puget Sound Energy's emission units.

Operating scenarios:

The facility is planned to operate year-round, with the exception of 7 days per year when liquefaction operations and vaporization operations would be shut down for maintenance. During this annual maintenance period, the ground flare would operate at a relatively low level and facility-wide emissions would be significantly less than during normal operation. Emission calculations for this permit application conservatively assume 8,760 hours per year facility operation and do not take credit for reduced emissions during annual maintenance.

The following summarizes the different operating scenarios that will occur as part of normal operation. The different cases presented below were provided by the design firm hired by PSE to build the plant – Chicago Bridge & Iron Company (CB&I) and represent various potential feed gas scenarios. As several sources of waste gas are disposed of via the flare, their relative compositions and flow rate vary depending on feed gas composition and operating rates of the various facility processes.

Facility Operating Scenarios:

A description of each scenario is included below the list.

1) Liquefying (No Vaporizing, gases from liquefying process operations)
2) Vaporizing (No Liquefying, Flare in "holding mode" explained below)
3) Liquefying and truck and/or ship loading
4) Vaporizing and truck and/or ship loading
5) Flare in holding mode, no other operations (e.g. maintenance shut down)
6) Flare in holding mode and truck and/or ship loading (all three waste gas flaring cases).

Under Scenario 1, the facility's liquefaction process is operating and natural gas is pretreated, chilled, and sent to the LNG storage tank. This scenario includes all five waste gas flaring cases (explained in more detail below).

Under Scenario 2, the LNG is being vaporized; liquefaction is not occurring and the flare is operating in what is called holding mode (meaning no liquefaction is occurring). The waste gas being sent to the flare during holding mode scenarios is composed of small amounts of gases from gas chromatograph speed loops; flare header sweeps; seal vents from one feed gas compressor and one refrigerant compressor; and heavy hydrocarbon storage flash gas. Scenario 2 (vaporizing) is not expected to occur more than 10 days per year whereas Scenario 1 (liquefying) could occur all hours of the year when not vaporizing.

For scenarios involving truck and/or ship loading, blow down and purge gas from the truck and ship loading operation may be flared during all operation scenarios (liquefying, vaporizing, or maintenance shutdown). Blow down and purge gas come from running nitrogen through the system once the LNG fueling is complete. The nitrogen acts to inert the fueling system. This is performed before any vessel is disconnected.

Several waste gas stream composition cases listed and described below are considered for the flare's two warm burners, one large and one small, (5 liquefying cases based on different feed gas composition and flare holding) and small cold burner (truck and/or ship loading).

There is a fourth burner, a large cold gas, and low-NO_x burner in the flare, which is only used for cryogenic gas during plant upset conditions which do not represent a normal or anticipated operating scenario. This scenario would only be during an emergency episode and it is not included in the emissions inventory or dispersion modeling scenarios.

Large Warm Burner Cases:

- **Liquefying Case 1:** Base Design / Low Btu; Design Composition (2% CO_2)
- **Liquefying Case 3:** "Normal" Operation; Alternative Heavy Composition (~0.2% CO_2)
- **Liquefying Case 4:** Maximum Hydraulic Flare Case; Alternative Heavy Composition (2% CO_2)
- **Liquefying Case 5:** High Specific Btu to Flare; Alternative Heavy Composition (~0.2% CO_2)

Small Warm Burner Cases:

- **Liquefying Case 2:** Facility Turndown; Average Composition (~0.5% CO_2)
- **Holding:** Facility Holding, No Liquefaction

Small Cold Burner Cases:

- **LNG Transfer Case A1:** Ship bunkering and truck loading at the same time
- **LNG Transfer Case A2:** Ship bunkering or truck loading, not both
- **LNG Transfer Case B:** Ship bunkering lean gas purge after initial rich gas purge

The following table summarizes the flare scenarios and references the corresponding facility operating scenario described above. The 'X' indicates which burner(s) within the flare assembly would be firing during each scenario.

Flare Emission Scenarios

Operating Scenario Number	Scenario Description	Modeling Source ID	Large Warm Gas Low-NO_x Burner	Small Warm Gas Standard Burner	Small Cold Gas Standard Burner
1	Liquefying Case 1	LW1	X		
1	Liquefying Case 2	SW2		X	
1	Liquefying Case 3	LW3	X		

1	Liquefying Case 4	LW4	X		
1	Liquefying Case 5	LW5	X		
3	Liquefying Case 1, Truck and Ship Loading A1	LWSC1A1	X		X
3	Liquefying Case 2, Truck and Ship Loading A1	SWSC2A1		X	X
3	Liquefying Case 3, Truck and Ship Loading A1	LWSC3A1	X		X
3	Liquefying Case 4, Truck and Ship Loading A1	LWSC4A1	X		X
3	Liquefying Case 5, Truck and Ship Loading A1	LWSC5A1	X		X
3	Liquefying Case 1, Truck or Ship Loading A2	LWSC1A2	X		X
3	Liquefying Case 2, Truck or Ship Loading A2	SWSC2A2			X
3	Liquefying Case 3, Truck or Ship Loading A2	LWSC3A2	X		X
3	Liquefying Case 4, Truck or Ship Loading A2	LWSC4A2	X		X
3	Liquefying Case 5, Truck or Ship Loading A2	LWSC5A2	X		X
3	Liquefying Case 1, Blow Down and Purge B	LWSC1B	X		X
3	Liquefying Case 2, Blow Down and Purge B	SWSC2B		X	X
3	Liquefying Case 3, Blow Down and Purge B	LWSC3B	X		X
3	Liquefying Case 4, Blow Down and Purge B	LWSC4B	X		X
3	Liquefying Case 5, Blow Down and Purge B	LWSC5B	X		X
2, 5	Flare Holding	FLAREH		X	
6	Flare Holding, Truck and Ship Loading A1	SWSCHA1		X	X
6	Flare Holding, Truck or Ship Loading A2	SWSCHA2		X	X

6	Flare Holding, Blow Down and Purge B	SWSCHB		X	X

The "flare holding scenario" applies when the vaporizer is running (maximum 10 days per year) or any other time the facility is not liquefying. Liquefaction cannot occur while vaporization is occurring and vice versa. When neither liquefaction nor vaporization is occurring, the flare operates in the holding mode. Thus the maximum liquefaction operating scenario consists of 8,760 hours per year of liquefaction and no vaporization/reinjection. The maximum vaporization operating scenario consists of 8,520 hours per year of liquefaction and 240 hours per year of vaporization. Therefore, in order to conservatively estimate emissions, emissions for each of the two operating scenarios were calculated. The highest annual emission rate for each pollutant between the two scenarios was used to calculate the worst-case annual total. The emissions would be highest for all pollutants except PM10/PM2.5 when the facility is liquefying. Therefore, for the purposes of the emissions calculations for the ground flare, emissions are conservatively estimated assuming that liquefying operations would occur every hour of the year (8,760 hours per year) for all pollutants except PM10/PM2.5. For PM10/PM2.5, emissions are assumed from liquefying operations occurring for 8,520 hours per year and vaporizing operations occur for 240 hours per year.

Emission Unit - LNG Vaporizer (66 MMbtu/hr)

This emission unit will be used in the Vaporizing operations and is expected to operate for no more than 240 hours per year (10 days per year) as proposed by the applicant. This 240 hour per year will be placed in the permit as an enforceable limit and the emission calculations for this unit will be based on this limitation.

Emissions Factors – Background
The emissions factors used for the calculations of natural gas combustion emissions from the LNG vaporizer are taken from EPA's WebFIRE online database (updated on 09/07/2016), California's Air Toxic Emission Factors online database (CATEF, updated in 1996), AB2588 Combustion Emissions Factors inventory (updated in 2001) and San Diego's Air Pollution Control District (SDAPCD) emissions inventory tables (updated in 2005).

WebFIRE contains emissions factors for criteria and hazardous air pollutants (HAP) for industrial and non-industrial processes and multiple reports submitted to the EPA using the Compliance and Emissions Data Reporting Interface (CEDRI) in response to regulatory requirements under Parts 60 and 63 of Title 40 of the U.S. Code of Federal Regulations (CFR). For this permitting case, emissions factors were chosen based on the following identifiers (with the exception of CO and NOx, which were given by CB&I and will be verified with performance testing):

1. SCC: 10300602
2. Type of equipment: external combustion boiler
3. Type of boiler: commercial/institutional
4. Types of fuel: natural gas
5. Size: 10-100 MMBtu
6. Control type: uncontrolled

7. Quality of data: only A, B, and C (EPA rating)
8. Natural gas pollutants: only non-criteria TAPs

CATEF contains approximately 2000 air toxics emission factors calculated from source test data collected for the Air Toxics Hot Spots Program. Most of the source test data is based on emission measurements from the early 1990's. CATEF is used to estimate air toxics emissions for the Air Toxics "Hot Spots" Program. For this permitting case, emissions factors were chosen based on the following identifiers:

1. SCC: 10100601
2. Type of equipment: boiler
3. Type of fuel: natural gas
4. Quality of data: only C3-v0 and B2-v2 (ARB rating)
5. Pollutants: only non-criteria TAPs
6. Type of value: The highest value between all emission factors sources

The AB2588 emission inventory was developed for the implementation of the AB2855 program by California's Air Resource Board (CARB). The emissions factors were to be used where source testing or fuel analysis were not required by the AB2588 Criteria and Guidelines Regulations, Appendix D. Ventura County Air Pollution Control District (VCAPCD) uses these emissions factors for permitting when specific data such as manufacturer's data, source tests, or fuel analysis is not available. For this permitting case, all the natural gas emissions factors were chosen.

San Diego Air Pollution Control District (SDAPCD) has developed emissions calculation procedures for combustion equipment used primarily to quantify emissions for permitting and reporting purposes. For this permitting case, emissions factors were chosen based on the following identifiers:

1. Tables: B17 (linked below in PDF)
    a. The link to this emission factor table found here: https://www.sandiegocounty.gov/content/dam/sdc/apcd/PDF/Misc/EFT/Gas_Combustion/APCD_Boiler_Natural_Gas_Fired_03-100_MMBtu_Low_NOx_Burners.pdf
2. Type of equipment: boiler
3. Types of fuel: natural gas
4. Size: 10-100 MMBtu
5. Pollutants: only non-criteria TAPs

<u>Emissions Factors – Metals</u>

The CATEF, AB2588 and SDAPCD inventories do not include metal emissions factors for the combustion of natural gas. Only WebFIRE presents metal emissions factors for natural gas combustion all of which were derived using source test data compiled in 1996 by Carnot Technical Services (CTS) for the Gas Research Institute (GRI) and the Electric Power Research Institute (EPRI).

As seen in Section 3.2, Table 3-1, Section 3.3 and Table 3-5 of CTS's report (TR-105646), cobalt, copper, lead, nickel, selenium and phosphorous were not detected in any of the natural gas fuel analyses. The only metals detected in the fuel analyses were arsenic and mercury. Barium, beryllium, cadmium, chromium, manganese, molybdenum and vanadium were not analyzed in the natural gas. The CTS report (TR-105646) presented emissions (more than the field blank) of cadmium, cobalt, lead, copper, barium, chromium, manganese, vanadium, molybdenum, nickel and phosphorous from at least one of the boiler exhaust stacks. However, since these metals were not detected or analyzed in the natural gas, there is not enough data to show that these metals were not as a result of surface contamination. The report mentions that the tested boilers used to burn fuel oil indicating that residual ash could have contaminated the results. In general, stack testing for metals is considered less reliable for emissions estimation purposes than mass balance techniques based on fuel analyses.

Aside from the CTS's report (TR-105646), there is substantial evidence showing that arsenic and mercury is present in natural gas in quantifiable amounts. The National Risk Management Research Laboratory has published research documentation[2] showing detection of elemental mercury at 2000 µg/L in natural gas condensate. A literature review[3] conducted by the Alberta Research Council, Inc. shows that U.S. natural gas pipelines can have elemental mercury concentrations up to 0.04 $\mu g/Nm^3$ and Alberta natural gas up to 0.08 $\mu g/Nm^3$. A survey[4] conducted by Universal Oil Products, LLC shows that concentrations of elemental mercury in North American natural gas can range up to 20 $\mu g/Nm^3$. Measurements presented at the Gas Quality and Energy Measurement Symposium[5] show that elemental mercury in SW Wyoming natural gas can range from 2 to 24 $\mu g/Nm^3$. Limited research[6] on natural gas arsenic content has been conducted at the Abo gas field in New Mexico showing arsenic (in the form of tertiary alkylarsines) concentrations ranging from 0.2 to 2.5 µg/L in natural gas condensate.

Since arsenic and mercury have sufficient vapor pressures to be present as a gas and there is research and data showing that natural gas contains these metals in quantifiable amounts, combustion emissions factors of mercury and arsenic will be used to calculate emissions from the vaporizer. Arsenic and mercury natural gas combustion emissions factors from the WebFIRE will be included in the emissions calculations and all other metals will not, due to lack of and inconsistent fuel analysis data.

<u>Emissions Factors Selection – Volatile Compounds</u>
WebFIRE presents emissions factors for various organic and inorganic volatile compounds for the combustion of natural gas, however, only formaldehyde, benzene, toluene, naphthalene, phenanthrene, 2-methylnapthalane and fluorene were detected at levels greater than the field blank. These results are presented in CTS's report (TR-105646). SDAPCD adopted WebFIRE's benzene, dichlorobenzene, formaldehyde, hexane, naphthalene and toluene natural gas combustion emissions factors. CATEF only presents natural gas combustion emissions factors for acetaldehyde, benzaldehyde, benzene and formaldehyde. The AB2588 inventory presents natural gas combustion emissions factors based on boiler stack testing for benzene, hexane, formaldehyde, naphthalene,

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[2] EPA Research and Development (2001) Mercury in Petroleum and Natural gas: Estimation of Emissions from Production, Processing, and Combustion. EPA/600/R-01/066
[3] Alberta Research Council Inc. (2009) Potential Release of Heavy Metals and Mercury from the UOG Industry into the Ambient Environment - Literature Review. Final Report
[4] Eckersley, N. (2010) Advanced Mercury Removal Technologies. Hydrocarbon Processing 29-35
[5] Crippen, K., Chao, S. (1997) Mercury in Natural Gas and Current Measurement Technology. Gas Quality and Energy Measurement Symposium, Orlando
[6] Delgado-Morales, W., Mohan, M. S., Zingaro, R.A. (1994) Analysis and Removal of Arsenic from Natural Gas Using Potassium Peroxydisulfate and Polysulfide Absorbents. International Journal of Environmental Analytical Chemistry 54, 203-220

toluene, xylenes, ethylbenzene, acetaldehyde, acrolein and propylene. In the case that there are multiple emission factors, the highest value was chosen for conservative purposes.

Emissions Factors – Criteria Pollutants, total VOCs and GHGs
CO, NO_x, PM, and total VOCs emissions factors for natural gas were derived from the boiler's manufacturer emissions data. Carbon dioxide, nitrous oxide and methane emissions factors were derived from EPA's AP-42 inventory.

Pollutant	Emissions Factor (lbs/MMscf)	Source
Acetaldehyde	8.47E-03	Maximum Value between CATEF (median value) and AB2588
Acrolein	2.70E-03	AB2588
Ammonia	3.20	WebFIRE and AB2588
Arsenic	2.04E-04	WebFIRE/AP-42
Pollutant	Emissions Factor (lbs/MMscf)	Source
Benzene	5.80E-03	Maximum Value out of WebFIRE, CATEF (median value), AB2588 and SDAPCD
Carbon dioxide	1.20E+05	WebFIRE
Carbon monoxide (CO)	40	Vendor design specification provided by CB&I.
Dichlorobenzene	1.20E-03	SDAPCD
Ethylbenzene	6.90E-03	AB2588
Formaldehyde	0.072	Maximum Value out of WebFIRE, CATEF (median value), AB2588 and SDAPCD
Hexane	1.8	WebFIRE/AP-42
Hydrocarbons (VOCs)	5.5	Vendor design specification provided by CB&I.
Mercury	2.60E-04	WebFIRE
Methane	2.30	WebFIRE
Naphthalene	6.1E-04	WebFIRE/AP-42
Nitrogen dioxide (NO_2)	1.13	10% of NO_x
Nitrogen oxides (NO_x)	12	Vendor design specification provided by CB&I.
Nitrous oxide	0.64	WebFIRE
Particulate matter (PM)	10.4	Cleaver Brooks emissions data
Propylene	0.53	AB2588
Sulfur dioxide (SO_2)	2.3	Calculated value[7]
Toluene	0.015	Average of WebFIRE, AB2588 and SDAPCD
Xylenes	0.02	AB2588

[7] Derived by SO2 Emission Factor (lb/MMcf) = [Natural Gas Density (lb/cf)] x [Sulfur Content (ppm)] / 106 x [64 g-SO2/32 g-S] x [Destruction Efficiency (%)] x [106 cf/MMcf]

PTE Emissions Calculations

A review was conducted for the maximum worst-case emissions, potential-to-emit (PTE) for the LNG Vaporizer. PTE is defined in WAC 173-400-030 as, "the maximum capacity of a source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is enforceable. Secondary emissions do not count in determining the potential to emit of a source."

Emissions were calculated for the LNG Vaporizer from the emission factors presented above. In the case of metal emission factors and some additional polycyclic organic matter, PSE still included any emission factors found in AP-42 for informational purposes.

For each pollutant, the emissions factor was multiplied by the amount of fuel used per time period to obtain the emissions rate.

The natural gas usage hourly rate with units in million square feet per hour is calculated using the following equation:

$$\mathrm{MMscf/hr} = \frac{[\text{boiler heat input}, 66\ \mathrm{MMBtu/hr}]}{[\text{natural gas heating value}, 0.001093\ \mathrm{MMBtu/scf}] * 1{,}000{,}000}$$

The hourly emissions rates for each pollutant from the combustion of natural gas are calculated using the following equation:

$$\text{lbs per hour} = [\text{emissions factor},\ \mathrm{lbs/MMscf}] * [0.0604, \mathrm{MMscf/hr}]$$

Emissions calculations for the vaporizer are documented in the following spreadsheet under tab "vapor" and summarized below:

Attachment A PSE
LNG Emissions_revise

Natural gas density (lb/cf) = 0.046
Sulfur Content of Fuel (ppmw) = 25

Summary of emissions for LNG vaporizer operating at 240 hours per year, Criteria Pollutants

Pollutant	Emission Factor (lb/MMcf)	Potential Emissions Hourly[a] (lbs/hr)	Annual[b] (tons/yr)
Criteria Pollutants			
$PM/PM_{10}/PM_{2.5}$	7.6	0.46	0.055
SO_2	2.3	0.14	0.017
NO_x	12	0.72	0.086
CO	40	2.4	0.29
VOCs	5.5	0.33	0.040
Lead	0.0005	3.0E-05	3.6E-06

Summary of emissions for LNG vaporizer operating at 240 hours per year, HAP/TAP

Pollutant	Emission Factor (lb/MMcf)	Potential Emissions	
		Hourly[a] (lbs/hr)	Annual[b] (tons/yr)
Hazardous Air Pollutants/Toxic Air Pollutants			
Acetaldehyde	8.5E-03	5.1E-04	6.1E-05
Acrolein	2.7E-03	1.6E-04	2.0E-05
Ammonia	3.2E+00	1.9E-01	2.3E-02
Arsenic	2.0E-04	1.2E-05	1.4E-06
Benzene	5.8E-03	3.5E-04	4.2E-05
Beryllium	1.2E-05	7.2E-07	8.7E-08
Cadmium	1.1E-03	6.6E-05	8.0E-06
Chromium(total)	1.4E-03	8.5E-05	1.0E-05
Cobalt	8.4E-05	5.1E-06	6.1E-07
Copper	8.5E-04	5.1E-05	6.2E-06
Ethylbenzene	6.9E-03	4.2E-04	5.0E-05
Formaldehyde	7.5E-02	4.5E-03	5.4E-04
Hexane	1.8E+00	1.1E-01	1.3E-02
Lead	5.0E-04	3.0E-05	3.6E-06
Manganese	3.8E-04	2.3E-05	2.8E-06
Mercury	2.6E-04	1.6E-05	1.9E-06
Naphthalene	6.1E-04	3.7E-05	4.4E-06

Summary of emissions for LNG vaporizer operating at 240 hours per year, HAP/TAP (cont.)

Pollutant	Emission Factor (lb/MMcf)	Potential Emissions Hourly[a] (lbs/hr)	Potential Emissions Annual[b] (tons/yr)
Nickel	2.1E-03	1.3E-04	1.5E-05
Polycyclic Organic Matter	1.9E-03	1.1E-04	1.4E-05
2-Methylnaphthalene	*2.4E-05*	1.4E-06	*1.7E-07*
3-Methylchloranthrene	*1.8E-06*	1.1E-07	*1.3E-08*
7,12-Dimethylbenz(a)anthracene	*1.6E-05*	9.7E-07	*1.2E-07*
Acenaphthene	*1.8E-06*	1.1E-07	*1.3E-08*
Acenaphthylene	*1.8E-06*	1.1E-07	*1.3E-08*
Anthracene	*2.4E-06*	1.4E-07	*1.7E-08*
Benz(a)anthracene	*1.8E-06*	1.1E-07	*1.3E-08*
Benzo(a)pyrene	*1.2E-06*	7.2E-08	*8.7E-09*
Benzo(b)fluoranthene	*1.8E-06*	1.1E-07	*1.3E-08*
Benzo(g,h,i)perylene	*1.2E-06*	7.2E-08	*8.7E-09*
Benzo(k)fluoranthene	*1.8E-06*	1.1E-07	*1.3E-08*
Chrysene	*1.8E-06*	1.1E-07	*1.3E-08*
Dibenzo(a,h)anthracene	*1.2E-06*	7.2E-08	*8.7E-09*
Dichlorobenzene	*1.2E-03*	7.2E-05	*8.7E-06*
Fluoranthene	*3.0E-06*	1.8E-07	*2.2E-08*
Fluorene	*2.8E-06*	1.7E-07	*2.0E-08*
Indeno(1,2,3-cd)pyrene	*1.8E-06*	1.1E-07	*1.3E-08*
Naphthalene	*6.1E-04*	3.7E-05	*4.4E-06*
Phenanathrene	*1.7E-05*	1.0E-06	*1.2E-07*
Pyrene	*5.0E-06*	3.0E-07	*3.6E-08*
Propylene	5.3E-01	3.2E-02	3.8E-03
Selenium	2.4E-05	1.4E-06	1.7E-07
Toluene	2.7E-02	1.6E-03	1.9E-04
Vanadium	2.3E-03	1.4E-04	1.7E-05
Xylenes	2.0E-02	1.2E-03	1.4E-04
Total HAPs		**0.12**	**0.014**

[a] Hourly Emissions (lb/hr) = [Maximum Heat Input (MMBtu/hr)] / [Fuel Heating Value (Btu/scf)] x [Emission Factor (lb/MMcf)]

[b] Annual Emissions (tons/yr) = [Maximum Fuel Usage (scf/hr)] x [1 MMscf/1,000,000 scf] x [Emission Factor (lb/MMcf)] x [Operating Hours (hrs/yr)] / [2,000 lbs/ton]

Emission Unit - Enclosed Ground Flare

The enclosed ground flare would be an air assisted burner flare that maintains a controlled stack temperature and retention time. The flare is planned to include four continuous flame pilots which will all be monitored by thermocouples. The proposed flare would include two large high-heat input burners and two low heat input burners.

The enclosed ground flare is designed to operate at a controlled stack temperature and retention time for achieving destruction of total hydrocarbons and VOCs. PSE LNG assumed a destruction efficiency of 99% for VOC, which is a conservative estimate as the vendor has designed the flare for 99.5% control. The ground flare would produce emissions from combustion of the waste gas streams that come from various processes throughout the facility. The waste gas cases were provided by Chicago Bridge and Iron Company (CB&I) to PSE LNG, including gas flow rate and gas characteristics, and are presented below:

Enclosed Ground Flare Waste Gas Cases

Equipment	Rate		Hours of Operation	Fuel
Enclosed Ground Flare				
Liquefying Case 1				
Waste Gas Flow	30,833	scf/hr	8,760	Waste Gas
Waste Gas Heat Input	10.2	MMBtu/hr		
Liquefying Case 2				
Waste Gas Flow	5,833	scf/hr	8,760	Waste Gas
Waste Gas Heat Input	2.5	MMBtu/hr		
Liquefying Case 3				
Waste Gas Flow	20,833	scf/hr	8,760	Waste Gas
Waste Gas Heat Input	34.5	MMBtu/hr		
Liquefying Case 4				
Waste Gas Flow	40,417	scf/hr	8,760	Waste Gas
Waste Gas Heat Input	35.6	MMBtu/hr		
Liquefying Case 5				
Waste Gas Flow	20,417	scf/hr	8,760	Waste Gas
Waste Gas Heat Input	37.2	MMBtu/hr		
Holding				
Waste Gas Flow	833	scf/hr	8,760	Waste Gas
Waste Gas Heat Input	0.9	MMBtu/hr		
LNG Transfer A1 (Ship and Truck)				
Waste Gas Flow	139	scf/min	104	Waste Gas
Waste Gas Heat Input	2.5	MMBtu/hr		
LNG Transfer A2/A3 (Ship or Truck)				
Waste Gas Flow	69	scf/min	484	Waste Gas
Waste Gas Heat Input	2.1	MMBtu/hr		
LNG Transfer B (after ship)				
Waste Gas Flow	69	scf/min	104	Waste Gas
Waste Gas Heat Input	0.93	MMBtu/hr		

"Flared Waste Gas Characteristics"

Parameters	Natural Gas	Flared Waste Gas									Diesel
		Liquefying Case 1	Liquefying Case 2	Liquefying Case 3	Liquefying Case 4	Liquefying Case 5	Holding	LNG Transfer A1	LNG Transfer A2/A3	LNG Transfer B	
Heat Content (Btu/scf)	1,093	346	466	1,644	864	1,825	1,144	506	506	223	138,000
Density (lb/scf)	0.046	0.101	0.091	0.088	0.097	0.087	0.049	0.058	0.059	0.067	
Sulfur Content (ppmw)[c]	25	337	912	524	250	587	17	0	0	0	15
VOC Content (wt%)	NA	9.6%	14%	51%	24%	58%	17%	0.10%	0.10%	0.10%	
Benzene Concentration ($\mu g/m^3$)[b]	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	2,980	
Ethylbenzene Concentration ($\mu g/m^3$)[b]	144	144	144	144	144	144	144	144	144	144	
m,p-Xylene Concentration ($\mu g/m^3$)[b]	986	986	986	986	986	986	986	986	986	986	
o-Xylene Concentration ($\mu g/m^3$)[b]	165	165	165	165	165	165	165	165	165	165	
Toluene Concentration ($\mu g/m^3$)[b]	2,570	2,570	2,570	2,570	2,570	2,570	2,570	2,570	2,570	2,570	

Notes:

[a] Provided by CB&I.

[c] Based on the Williams Gas Pipeline tariff of 0.25 grains per 100 cubic feet for H2S, the past 12-month maximum total sulfur (reported as H2S by Williams Gas Pipeline) of 0.603 grains per 100 cubic feet, and sulfur from odorant of 0.23 grains per 100 cubic feet (odorant injection rates provided by PSE).

[b] From "Natural Gas Analysis"; Environmental Partners, Inc.; February 3, 2014. Most hazardous air pollutants (HAPs) will go through with the heavy hydrocarbons, but the fraction is unknown. Therefore, we conservatively assume the waste gas has the full concentration of HAP.

<u>Sulfur in the waste gas streams/SOx emissions:</u>

One pollutant of concern from the enclosed ground flares is the production of sulfur containing compounds. As several sources of waste gas are disposed of via the flare, their relative compositions and flows vary depending on feed gas composition coming into the facility and operating rates of the various facility processes, which in turn affects the fraction of sulfur in each flare inlet case. The six facility operating cases presented below are intended to bracket the operating ranges the flare is expected to accommodate during operation.

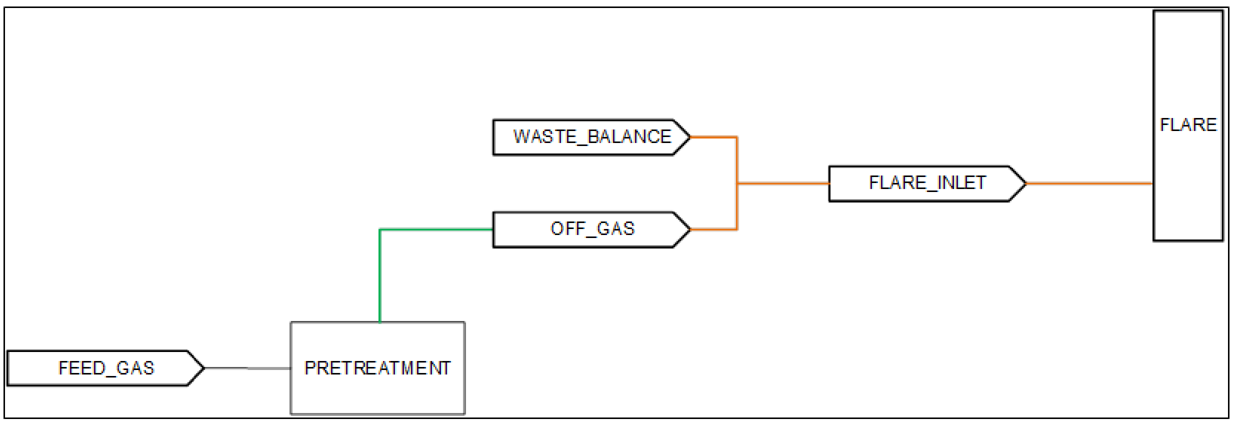
- **Case 1:** Base Design / Low Btu; Design Composition (2% CO_2)
- **Case 2:** Facility Turndown; Average Composition (~0.5% CO_2)
- **Case 3:** "Normal" Operation; Alternative Heavy Composition (~0.2% CO_2)
- **Case 4:** Maximum Hydraulic Flare Case; Alternative Heavy Composition (2% CO_2)
- **Case 5:** High Specific Btu to Flare; Alternative Heavy Composition (~0.2% CO_2)
- **Holding:** Facility Holding, No Liquefaction

Sulfur in the feed gas is a combination of total sulfur (reported as H_2S) in natural gas from the Williams Northwest Pipeline and odorants added later by both Williams Pipeline and PSE LNG (methyl ethyl sulfide, C_3H_8S; and tert-Butyl Mercaptan, tert-$C4H_{10}S$). The amount of total sulfur and odorants in the facility feed gas varies continuously. The maximum H_2S and total sulfur content of the pipeline gas is limited by the Williams Northwest Pipeline tariff to be below 0.25 grain of H_2S per one hundred cubic feet (gr/hcf) and 5 gr/hcf total sulfur (reported as H_2S). Odorants are added to the pipeline gas when the gas enters the distribution system. Odorant is injected by Williams Northwest Pipeline at a rate of approximately 0.077 gr/hcf and injected by PSE at a rate of 0.15 gr/hcf. This adds 0.23 gr/hcf of sulfur to the feed gas of the plant.

In order to calculate a conservative estimate, flare inlet sulfur loading was estimated using recent actual data of total sulfur H_2S in Williams Northwest Pipeline natural gas. In the past 12 months, the maximum total sulfur concentration reported by Williams Northwest Pipeline was 0.603 gr/hcf (reported as H_2S) and the maximum H_2S concentration was 0.238 gr/hcf. The 12-month averages were 0.421 gr/hcf total sulfur (as H_2S) and 0.057 gr/hcf H_2S. See the attached spreadsheet for sulfur data since 8/18/15:

Revised Attachment D Waste Gas Case Da

Most of the incoming H_2S and some of the other reduced sulfur compounds will be removed in the LNG Facility's pretreatment process and off gases from the pretreatment process will be sent to the flare (see flow chart).



In the emission calculations, it is assumed that the H_2S concentration in the feed gas is equal to the tariff value of 0.25 gr/hcf and that all sulfur from H_2S is sent to the flare. PSE LNG also assumes in their application that 80% of the other reduced sulfur compounds and odorants will be removed in the pretreatment process and sent to the flare. The rest of the sulfur is removed with the heavy hydrocarbons or stays in the natural gas that is liquefied.

Emission factors of SO_2 are therefore estimated using the following equation:

SO_2 Emission Factor (lb/MMcf) = [Gas Density (lb/cf)] x [S Content (ppmw)] / 10^6 x [64 g- SO_2 /32 g-S] x [Destruction Efficiency (%)] x [106 cf/MMcf]

Where each flare case has specific sulfur content, gas density and 99% of the waste gas is oxidized to SO_2.

Parameters	Natural Gas[a]	Flared Waste Gas[a]								
		Liquefying Case 1	Liquefying Case 2	Liquefying Case 3	Liquefying Case 4	Liquefying Case 5	Holding	LNG Transfer A1	LNG Transfer A2/A3	LNG Transfer B
Density (lb/scf)	0.046	0.101	0.091	0.088	0.097	0.087	0.049	0.058	0.059	0.067
Sulfur Content (ppmw)[c]	25	337	912	524	250	587	17	0	0	0

CO emissions:

Carbon monoxide emissions were estimated from the flare manufacturer based on the design and the methane content of waste gases entering the flare. For example, the CO emission factor for liquefying case 1 is 0.075 lbs/MMscf, and the CO emissions factor for liquefying case 2 is 0.196 lbs/MMscf. Each emission factor was using the following equation:

Annual Emissions (tons/yr) = [Maximum Fuel Usage (scf/hr)] x [1 MMscf/1,000,000 scf] x [Emission Factor (lb/MMcf)] x [8760 (hrs/yr)] / [2,000 lbs/ton]

Where each flare case has a specific fuel usage rate that is expected per vendor design specifications (CB&I) as shown in the table above titled "**Enclosed Ground Flare Waste Gas Cases**"

VOC emissions:

VOC emissions are based on the VOC content in the waste streams going to the flare.
The above table titled "Flare Waste Gas Characteristics" outlines total VOC content % for each flare case. Each emission factor for VOC was calculated using the following formula for each case:

Emission Factor (lb/MMcf) = [Gas Density (lb/cf)] x [VOC Content (wt%)] x [99 % Destruction efficiency (%)] x [10^6 cf/MMcf]

Parameters	Natural Gas	Flared Waste Gas								
		Liquefying Case 1	Liquefying Case 2	Liquefying Case 3	Liquefying Case 4	Liquefying Case 5	Holding	LNG Transfer A1	LNG Transfer A2/A3	LNG Transfer B
Density (lb/scf)	0.046	0.101	0.091	0.088	0.097	0.087	0.049	0.058	0.059	0.067
VOC Content (wt%)	NA	9.6%	14%	51%	24%	58%	17%	0.10%	0.10%	0.10%

NOx emissions:

NOx emissions were estimated from the flare manufacturer based on the design and the amount of excess air combusted in the flare. For example, the NOx emission factor for liquefying case 1 is 0.023 lbs/MMscf, and the NOx emissions factor for liquefying case 2 is 0.066 lbs/MMscf. Each emission factor was using the following equation:

Annual Emissions (tons/yr) = [Maximum Fuel Usage (scf/hr)] x [1 MMscf/1,000,000 scf] x [Emission Factor (lb/MMcf)] x [8760 (hrs/yr)] / [2,000 lbs/ton]

Where each flare case has a specific fuel usage rate that is expected per vendor design specifications (CB&I) as shown in the table above titled "**Enclosed Ground Flare Waste Gas Cases**"

Particulate Matter Emissions:

Particulate matter emissions (PM, PM10 and PM2.5) were estimated using EPA's AP-42 Office of Air Quality Planning and Standards, US Environmental Protection Agency. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, Chapter 1.4, Table 1.4-2: Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion. Heat input was taken from manufacturer data supplied by CB&I, and the highest value was taken for each scenario to get potential emissions:

Annual Emissions (tons/yr) = [Heat Input (MMbtu/hr)] x [Emission Factor (lb/MMbtu)] x [8760 (hrs/yr)] / [2,000 lbs/ton]

TAC/HAP Emissions:
Hazardous Air pollutants and Toxic Air contaminant emissions were estimated using a variety of methods depending on information available.

Benzene, toluene, ethylbenzene, and xylenes (BTEX) were based on composition of the waste gas and the 99% destruction efficiency of the flare. Some of the BTEX would partition into the heavy hydrocarbon storage, but this fraction is unknown and so a more conservative estimate was used – all BTEX goes to the flare.

HAP/TAP emissions were estimated using EPA's AP-42 Office of Air Quality Planning and Standards, US Environmental Protection Agency. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, Chapter 1.4, Table 1.4-3: Emission Factors for Speciated Organic Compounds from Natural Gas Combustion. Some of the TAPs/HAPs not listed in AP-42 were estimated using the maximum value out of California Air Toxics Emission Factors (median value), EPA's Web Factor Information Retrieval System (WebFIRE) database, San Diego Air Pollution Control District emission factor tables, and Ventura County Air Pollution Control District's default emission factors for AB2588 reporting. The highest value from the list was chosen for conservative purposes.

Metal HAP/TAC were estimated using AP-42 chapter 1.4, Table 1.4-4: Emission Factors for Metals from Natural Gas Combustion.

As described above under the waste gas cases, emissions were calculated for each of the scenarios. From these scenarios, the worst case emissions were taken for each pollutant to get a conservative estimate of emissions. They are summarized below, and outlined in detail below in the plant wide emission summary with the excel file "Attachment A PSE LNG Emissions".

	Enclosed Ground Flare (Worst-case)	
Pollutant	**(lb/hr)**	**(tpy)**
Criteria Pollutants		
PM/PM_{10}/$PM_{2.5}$	0.28	1.2
Sulfur dioxide (SO_2)	2.1	9.1
Nitrogen oxides (NO_X)	0.86	3.7
Carbon monoxide (CO)	2.7	12
VOCs	10	45
Lead	1.8E-05	8.0E-05
Total HAPs	0.1	0.30

Emission Unit – Fugitive Pipe Leaks:

Process fugitive VOC emissions can occur from leaks in valves, pump seals, flanges, connectors, and compressor seals. All the proposed pumps used by PSE with the exception of the heavy hydrocarbon liquid pump, will be submerged inside enclosed liquid storage tanks. There is also a seal leak recovery system for the refrigerant compressor that captures 90 percent of the leak losses, with the remaining 10 percent sent to the flare. The leaks from the feed gas compressor seals would also be captured and vented to the flare. The compressor seals for mixed refrigerant storage, the regeneration pretreatment system, and the boil off gas would have fugitive emissions vented to the atmosphere. In addition, there are several valves, relief valves, and flanged connectors for conveyance of various process fluids that have the potential for fugitive leaks. LNG bunkering of ships at the TOTE terminal would not produce any fugitive emissions. However, there are 4 swivel joints that have seals with the potential to leak LNG. The leak rate of a swivel joint is assumed to be equal to that of a pump seal for the purposes of emission calculations. Component count considered "in fluid service" were provided in the application.

Component Counts

		Fluid Serviced								
Component	**Phase**	**Acid gas**	**Boil-Off Gas**	**Ethylene**	**Fuel Gas**	**Hydrocarbon Liquid**	**Liquefied Natural Gas**	**Mixed Refrigerant**	**Natural Gas**	**Natural Gas**
Valves	Gas/Vapor	39	9	12	36			112	185	30
	Light Liquid					33	244			
Pump Seals	Light Liquid					1				
Flanges/Connectors	Gas/Vapor	0	7	2	15			28	77	15
	Light Liquid					6	114			
Compressor Seals	Gas/Vapor	0	2	0	0	0	0	1	1	0
Relief Valves	Gas/Vapor	3	0	1	3	1	19	8	9	2
Swivel Joints	Light Liquid						4			

Fugitive emission calculations used emission factors for "terminal/Depot" emission sources from South Coast Air Quality Management District's guidelines for (SCAQMD 2003). In this document, emission factors are higher for light liquid service than for heavy liquid service; therefore, the hydrocarbon liquid and LNG fluids are conservatively estimated to be in light liquid service. As discussed in the BACT section of this worksheet, PSE will implement a leak detection and repair program to make sure leaks from these sources are at a minimum. A conservative estimate of control from the LDAR was used from the Texas Commission for Environmental Quality (TCEQ) 28M LDAR, which states 75% control for valves, pumps, compressors, and relief valves, and 30% for flanges for both gas and light liquid service. These values are lower than EPA values used in other projects (88% for light liquid service, and 92% for gas service).

Neither methane nor ethane (components of LNG) are considered VOCs at the federal level or in Washington, but to be conservative, it is assumed that 100% of the leak emissions would be VOCs. Also it is assumed that the entire benzene, toluene, ethylbenzene, and xylenes concentration in the natural gas feed is present in every fluid service by all the listed equipment.

FLUID HAP/TAP CONTENT

Pollutant	CAS / ID	Acid gas	Boil-Off Gas	Ethylene	Fuel Gas	Fluid Hydrocarbon Liquid	Liquefied Natural Gas	Mixed Refrigerant	Natural Gas	Untreated Natural Gas
VOC Content (%wt)	VOC	100%	100%	100%	100%	100%	100%	100%	100%	100%
n-Hexane (ppmw)	110-54-3	70	5.7E-10	0	1,185	210,669	27	0	1,185	1,185
Hydrogen sulfide (ppmw	2148878	3,128	0.00035	0	22	0.010	0.21	0	22	166
Benzene (ppmw)	71-43-2	4.0	4.0	0	4.0	4.0	4.0	0	4.0	4.0
Ethylbenzene (ppmw)	100-41-4	0.20	0.20	0	0.20	0.20	0.20	0	0.20	0.20
m,p-Xylene (ppmw)	106-42-3	1.3	1.3	0	1.3	1.3	1.3	0	1.3	1.3
o-Xylene (ppmw)	95-47-6	0.22	0.22	0	0.22	0.22	0.22	0	0.22	0.22
Toluene (ppmw)	108-88-3	3.5	3.5	0	3.5	3.5	3.5	0	3.5	3.5

Pollutant concentration was converted to ppmw using the following equation

Pollutant Concentration (ppmw) = [Pollutant Concentration (mg/m3)] / [453.6 g/lb] / [10^6 mg/g] / [35.31 ft3/m3] / [Gas Density (lb/cf)] x 10^6

The benzene, toluene, ethylbenzene, and xylenes concentrations below were supplied by CB&I and used to calculate hourly and annual emissions for each compound assuming leaks occurred 8760 hours per year to be conservative.

Benzene Concentration (mg/m^3) = 2,980

Ethylbenzene Concentration (mg/m^3) = 144

m,p-Xylene Concentration (mg/m^3) = 986

o-Xylene Concentration (mg/m^3) = 165

Toluene Concentration (mg/m^3) = 2,570

Natural Gas Density (lb/scf) = 0.046

Emissions are summarized in the table below.

Summary of Hourly and Annual Emissions
Fugitive Pipe Leaks

Pollutant	Total
Hourly Emissions[a] (lb/hr)	
VOCs	**0.95**
n-Hexane	**0.014**
Hydrogen sulfide	**1.0E-04**
Benzene	**3.4E-06**
Ethylbenzene	**1.6E-07**
m,p-Xylene	**1.1E-06**
o-Xylene	**1.9E-07**
Toluene	**2.9E-06**
Total HAPs	1.4E-02
Annual Emissions[a] (tpy)	
VOCs	**4.2**
n-Hexane	**0.061**
Hydrogen sulfide	**4.5E-04**
Benzene	**1.5E-05**
Ethylbenzene	**7.2E-07**
m,p-Xylene	**4.9E-06**
o-Xylene	**8.3E-07**
Toluene	**1.3E-05**
Total HAPs	6.1E-02

[a] Hourly Emissions (lb/hr) = [Emission Factor (lb/hr per component)] x [Component Count] x [Pollutant Content (%wt)] x [1 - LDAR Control Efficiency (%)]

Annual Emissions (tpy) = [Emission Factor (lb/hr per component)] x [Component Count] x [Pollutant Content (%wt)] x [1 - LDAR Control Efficiency (%)] x [Hours of Operation (hrs/yr)] / [2,000 lb/ton]

Hours of Operation (hrs/yr) = 8,760

<u>Plant wide Emission Calculation:</u>

All emission calculations were supplied by the PSE and verified by PSCAA for accuracy. The highest value was taken from each operating scenario and used as the worst case potential to emit (small cold burner operations, large warm burner operations and LNG transfer operation).

Assumptions relied upon in the emission calculations are enforceable permit conditions to ensure the facility does not exceed the calculated potential to emit outlined below:

Attachment A PSE LNG Emissions_revise

PSE updated these emission calculations from what was originally submitted in the application due to a minor summation error. The original HAP number included TAPs, which not all TAPs are HAPs.

Pollutant	Facility-Wide Total Worst-Case (lb/hr)	Facility-Wide Total Worst-Case (tpy)
Criteria Pollutants		
$PM/PM_{10}/PM_{2.5}$	0.48	1.2
Sulfur dioxide (SO_2)	2.1	9.1
Nitrogen oxides (NO_X)	1.0	3.8
Carbon monoxide (CO)	3.2	12
VOCs	11	49
Lead	3.2E-05	8.2E-05
Total HAPs	0.1	0.37
Total TAPs	1.90	1.03

Source	CO_2 Emission Factor (lb/MMBtu)	CO_2 Emission Rate (MT/yr)	CH_4 Emission Rate (MT/yr)	N_2O Emission Factor (lb/MMBtu)	N_2O Emission Rate (MT/yr)	Total CO_2 Equivalent (MT/yr)
Flare	--	27,110	40	0.00022	0.033	28,131
Vaporizer	117	841	0.036	0.00022	0.0016	842
Fugitives	--	--	3.8	--	--	95
Total	--	27,950	44	--	0.034	29,067

G. OPERATING PERMIT or PSD

Air Operating Permit Applicability
A major source, as defined in chapter 173-401 WAC, is required to get an air operating permit under Regulation 1 Article 7 of the Puget Sound Clean Air Agency. A major source is defined as one of the following:

(a) any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit, in the aggregate, ten tons per year (tpy) or more of any hazardous air pollutant which has been listed pursuant to section 112(b) of the FCAA, or twenty-five tpy or more of any combination of such hazardous air pollutants; or

(b) A major stationary source that directly emits or has the potential to emit, one hundred tpy(tons per year) or more of any air pollutant subject to regulation (including any major source of fugitive emissions of any such pollutant); or

(c) A major source as defined in Part D of Title I of the FCAA.

Note: Fugitive emissions are only counted for categorical sources listed in (b) of 173-401 WAC (29)

This project does not trigger the threshold values identified above to qualify as a major source.

Prevention of Significant Deterioration (PSD):
A proposed project is only subject to PSD permitting if the facility or the project has the potential to emit 100 tpy of a regulated air pollutant and is included in the list of source categories identified below or if

the facility or proposed project has the potential to emit 250 tpy of a regulated air pollutant and the type of facility is not listed below.

28 Source Categories

Coal cleaning plants with thermal dryers	Charcoal production plants
Portland cement plants	Kraft pulp mills
Iron and steel mills	Primary zinc smelters
Primary copper smelters	Primary aluminum ore reduction plants
Hydrofluoric acid plants	Municipal incinerator capable of charging more than 250 tons of refuse per day
Nitric acid plants	Sulfuric acid plants
Lime plants	Petroleum refineries
Coke oven batteries	Phosphate rock processing plants
Carbon black plants (furnace process)	Sulfur recovery plants
Fuel conversion plants	Primary lead smelters
Secondary metal production plants	Sintering plants
Fossil fuel boilers (or combination thereof) totaling more than 250 MMBtu/hr heat input	Chemical process plants (does not include ethanol production facilities that produce ethanol by natural fermentation, included in NAICS codes 325193 or 312140)
Fossil fuel fired steam electric plants of more than 250 MMBtu/hr heat input	Petroleum storage transfer units, total storage capacity over 300,000 barrels
Taconite ore processing plants	Glass fiber processing plants

This project does not trigger the threshold values and is not subject to the permitting requirements under PSD.

H. AMBIENT TOXICS IMPACT ANALYSIS

The Clean Air Act identifies 187 Hazardous Air Pollutants (or HAPs) for regulation. HAPs are pollutants "known to cause or may reasonably be anticipated to cause adverse effects to human health or adverse environmental effects" [Section 112 (b)]. HAPs are regulated by specified controls known as Maximum Achievable Control Technology standards (MACTs) and Generally Achievable Control Technology standards (GACTs).

In comparison, Agency Regulation 3, Section 2.07 is the review of new Toxic Air Contaminants (TACs) (or TAPs) Sources. This rule requires that new sources that emit toxic air contaminants undergo a review of toxic air contaminant emissions. Definitions and procedures contained in Chapter 173-460 WAC and adopted by reference in Regulation I, Section 6.01(a) apply. The TAP list in the WAC includes small quantity emission rates (SQERs) which were used to determine if the new source of TAPs need to conduct modeling. Not all the TAPs listed in the rule are HAPs, and not all HAPs are considered TAPs. It depends on the list in WAC 173-460-150.

Additionally, some of the pollutants on the TAP list are also criteria pollutants – Carbon Monoxide (CO), Nitrogen Oxides (NOx), and Sulfur Dioxide (SO_2).

First tier review involves comparing the emissions of each toxic air contaminant discharged to atmosphere to the SQER listed in WAC 173-460-150; or, the dispersion modeling, using an EPA-approved model, can be used to demonstrate that the predicted concentration of each contaminant is below the corresponding ASIL listed in WAC 173-460-150. The applicant can also submit a more comprehensive evaluation including the use of other EPA guideline models and more accurate emission estimation techniques to demonstrate that the predicted concentration of each contaminant is below the corresponding ASIL listed in WAC 173-460-150 in all areas where the general public has access.

Analysis:

Emission calculations for all TAPs and criteria pollutants are evaluated in detail above in the emission calculation section and the results are included in the table below. From all the different waste gas cases analyzed and taking the worst case scenario emissions from “Small cold burner operations”, “Large Warm Burner Operations” and “LNG transfer operations” and then adding those up with fugitive emissions (if there are TAPs) and the Vaporizer/Liquefying emissions - worst case scenario emissions are presented below for Both HAPs and TAPs:

CAS / ID	Pollutant	Worst-Case Operating Scenario		
		lb/hr	tpy	pounds/yr
PM	$PM/PM_{10}/PM_{2.5}$	4.8E-01	1.2E+00	2.5E+03
2025884	SO_2	2.1E+00	9.1E+00	1.8E+04
Nox	NO_x	1.0E+00	3.8E+00	7.6E+03
630-08-0	CO	3.2E+00	1.2E+01	2.4E+04
VOC	VOCs	1.1E+01	4.9E+01	9.8E+04
7439-92-1	Lead	3.2E-05	8.2E-05	1.6E-01
75-07-0	Acetaldehyde	5.4E-04	1.4E-03	2.8E+00
107-02-8	Acrolein	1.7E-04	4.4E-04	8.8E-01
7664-41-7	Ammonia	1.7E+00	5.2E-01	1.0E+03
7440-38-2	Arsenic	1.3E-05	3.3E-05	6.5E-02
71-43-2	Benzene	3.6E-04	3.3E-04	6.6E-01
7440-41-7	Beryllium	7.6E-07	2.0E-06	3.9E-03
7440-43-9	Cadmium	7.0E-05	1.8E-04	3.6E-01
7440-47-3	Chromium(total)	8.9E-05	2.3E-04	4.6E-01
7440-48-4	Cobalt	5.4E-06	1.4E-05	2.7E-02
Cu	Copper	5.4E-05	1.4E-04	2.8E-01
100-41-4	Ethylbenzene	4.2E-04	6.4E-05	1.3E-01
50-00-0	Formaldehyde	4.8E-03	1.2E-02	2.4E+01
110-54-3	Hexane	1.3E-01	3.5E-01	7.1E+02
2148878	Hydrogen sulfide	1.1E-02	4.9E-02	9.9E+01
7439-92-1	Lead	3.2E-05	8.2E-05	1.6E-01
7439-96-5	Manganese	2.4E-05	6.2E-05	1.2E-01
7439-97-6	Mercury	1.7E-05	4.2E-05	8.5E-02
7440-02-0	Nickel	1.3E-04	3.4E-04	6.9E-01
POM	Polycyclic Organic Matter	1.2E-04	3.1E-04	6.2E-01
91-57-6	*2-Methylnaphthalene*	1.5E-06	3.9E-06	7.8E-03
56-49-5	*3-Methylchloranthrene*	1.1E-07	2.9E-07	5.9E-04
57-97-6	*7,12-Dimethylbenz(a)anthracene*	1.0E-06	2.6E-06	5.2E-03
83-32-9	*Acenaphthene*	1.1E-07	2.9E-07	5.9E-04
208-96-8	*Acenaphthylene*	1.1E-07	2.9E-07	5.9E-04
120-12-7	*Anthracene*	1.5E-07	3.9E-07	7.8E-04
56-55-3	*Benz(a)anthracene*	1.1E-07	2.9E-07	5.9E-04
50-32-8	*Benzo(a)pyrene*	7.6E-08	2.0E-07	3.9E-04
205-99-2	*Benzo(b)fluoranthene*	1.1E-07	2.9E-07	5.9E-04
191-24-2	*Benzo(g,h,i)perylene*	7.6E-08	2.0E-07	3.9E-04
207-08-9	*Benzo(k)fluoranthene*	1.1E-07	2.9E-07	5.9E-04
218-01-9	*Chrysene*	1.1E-07	2.9E-07	5.9E-04
53-70-3	*Dibenzo(a,h)anthracene*	7.6E-08	2.0E-07	3.9E-04
106-46-7	*Dichlorobenzene*	7.6E-05	2.0E-04	3.9E-01
206-44-0	*Fluoranthene*	1.9E-07	4.9E-07	9.8E-04
86-73-7	*Fluorene*	1.8E-07	4.6E-07	9.1E-04
193-39-5	*Indeno(1,2,3-cd)pyrene*	1.1E-07	2.9E-07	5.9E-04
91-20-3	*Naphthalene*	3.9E-05	1.0E-04	2.0E-01
85-01-8	*Phenanathrene*	1.1E-06	2.8E-06	5.5E-03
129-00-0	*Pyrene*	3.2E-07	8.2E-07	1.6E-03
115-07-1	Propylene	3.2E-02	8.6E-02	1.7E+02
7782-49-2	Selenium	1.5E-06	3.9E-06	7.8E-03
108-88-3	Toluene	1.6E-03	4.4E-04	8.8E-01
7440-62-2	Vanadium	1.4E-04	3.7E-04	7.5E-01
106-42-3	m,p-Xylene	1.2E-03	2.4E-04	4.7E-01
95-47-6	o-Xylene	5.1E-06	1.6E-05	3.3E-02
HAP	**Total HAPs**	1.4E-01	3.7E-01	7.4E+02

Total TAP (HAPs that are not TAP were not included in the table below) emissions are presented below with each pollutant's small quantity emissions rate. (Note: PSCAA did not adopt the de minimis values listed in the WAC; however, the applicant included these values for informational purposes only).

Pollutant	CAS Number	Averaging Period	Emission Rate	*De Minimis*[a]	SQER[a]
			(pounds per averaging period)		
1,4-Dichlorobenzene	106-46-7	year	0.39	0.872	17.4
3-Methylchloranthrene	56-49-5	year	5.9E-04	0.00153	0.0305
7,12-Dimethylbenz(a)anthracene	57-97-6	year	0.0052	0.000135	0.00271
Acetaldehyde	75-07-0	year	2.8	3.55	71
Acrolein	107-02-8	24-hr	0.0041	0.000394	0.00789
Ammonia	7664-41-7	24-hr	41	0.465	9.31
Arsenic	7440-38-2	year	0.065	0.00291	0.0581
Benz(a)anthracene	56-55-3	year	5.9E-04	0.0872	1.74
Benzene	71-43-2	year	0.66	0.331	6.62
Benzo(a)pyrene	50-32-8	year	3.9E-04	0.00872	0.174
Benzo(b)fluoranthene	205-99-2	year	5.9E-04	0.0872	1.74
Benzo(k)fluoranthene	207-08-9	year	5.9E-04	0.0872	1.74
Beryllium	7440-41-7	year	0.0039	0.004	0.08
Cadmium	7440-43-9	year	0.36	0.00228	0.0457
Carbon monoxide	630-08-0	1-hr	3.2	1.14	50.4
Chrysene	218-01-9	year	5.9E-04	0.872	17.4
Cobalt	7440-48-4	24-hr	1.3E-04	0.000657	0.013
Copper	Cu	1-hr	5.4E-05	0.011	0.219
Dibenzo(a,h)anthracene	53-70-3	year	3.9E-04	0.00799	0.16
Dichlorobenzene	106-46-7	year	3.9E-01	0.872	17.4
Ethylbenzene	100-41-4	year	0.13	3.84	76.8
Formaldehyde	50-00-0	year	24	1.6	32
Hexane	110-54-3	24-hr	3.1	4.6	92
Hydrogen sulfide	2148878	24-hr	0.27	0.0131	0.263
Indeno(1,2,3-cd)pyrene	193-39-5	year	5.9E-04	0.0872	1.74

Pollutant	CAS Number	Averaging Period	Emission Rate	*De Minimis*[a]	SQER[a]
Lead	7439-92-1	year	0.16	10	16
m,p-Xylene	106-42-3	24-hr	0.029	1.45	29
Manganese	7439-96-5	24-hr	5.8E-04	0.000263	0.00526
Mercury	7439-97-6	24-hr	4.0E-04	0.000591	0.0118
Naphthalene	91-20-3	year	0.20	0.282	5.64
Nitrogen dioxide	10102-44-0	1-hr	0.10	0.457	1.03
o-Xylene	95-47-6	24-hr	1.2E-04	1.45	29
Propylene	115-07-1	24-hr	0.78	19.7	394
Selenium	7782-49-2	24-hr	3.7E-05	0.131	2.63
Sulfur dioxide	2025884	1-hr	2.1	0.457	1.45
Toluene	108-88-3	24-hr	0.039	32.9	657
Vanadium	7440-62-2	24-hr	0.0035	0.00131	0.0263

Pollutant	CAS Number	Emission Rate	*De Minimis*[a]	SQER
		(pounds per year)		
Chromium(VI)	18540-29-9	0.46	0.000064	0.00128

All TAPs except the six pollutants listed below were below their respective SQER. TAPs below the SQER require no further review:

Pollutant	CAS Number	Averaging Period	ASIL[a] ($\mu g/m^3$)
7,12-Dimethylbenz(a)anthracene	57-97-6	year	0.0000141
Ammonia	7664-41-7	24-hr	70.8
Arsenic	7440-38-2	year	0.000303
Cadmium	7440-43-9	year	0.000238
Hydrogen sulfide	2148878	24-hr	2
Sulfur dioxide	2025884	1-hr	660

These six pollutants were modeled by PSE to determine if their emissions would exceed the acceptable source impact levels (ASIL) values.

Modeling files were supplied with the application and reviewed by the agency for accuracy. Air dispersion modeling was conducted in accordance with the 40 CFR Part 51 Appendix W. The first modeling results provided by PSE did not use the meteorological monitoring station(s) that best represented the area where the LNG is proposed to be located. The PSCAA Tideflats monitoring station is the most representative source of wind data (speed and direction) for PSE LNG. However, Tideflats monitoring station does not record all necessary parameters to accurately run an air dispersion model and additionally, some of the necessary wind data was missing. The missing data was obtained from the following meteorological stations:

• SeaTac Airport (wind speed and direction, temperature, relative humidity (RH), pressure and cloud cover);
• McChord AFB: (wind speed and direction, temperature, RH, pressure and cloud cover); and
• Tacoma South L Street: (wind speed and direction, temperature, RH, and pressure).

PSE modified their analysis by modeling four different scenarios to find the highest predicted concentration of each TAP:

Scenario 1 - SeaTac as the primary source of temperature, RH, pressure and cloud cover data, and wind speed and direction substitution when Tideflats is missing;

Scenario 2 – Tacoma South L as the primary source of temperature, RH and pressure, and wind speed and direction substitution when Tideflats is missing, and SeaTac provides cloud cover and substitutes during hours when Tideflats and Tacoma South L are both missing;

Scenario 3 – McChord as the primary source of temperature, pressure and cloud cover data, and wind speed and direction substitution when Tideflats is missing; and

Scenario 4 – Tacoma South L as the primary source of temperature, RH, pressure data, and wind speed and direction substitution when Tideflats is missing, and McChord provides cloud cover and substitutes during hours when Tideflats and Tacoma South L are both missing.

AERMOD was then set up using all 4 different scenarios described above with their respective meteorological data, and then using the worst case emission rates per pollutant from the following 6 operating modes:

1) Liquefying (includes five waste gas cases)
2) Vaporizing (flare in holding mode)
3) Liquefying (all five waste gas cases) and truck and/or ship loading (all three waste gas cases)
4) Vaporizing (flare in holding mode) and truck and/or ship loading (all three waste gas cases)
5) Flare in holding mode, no other operations (e.g. maintenance shut down)
6) Flare in holding mode and truck and/or ship loading (all three waste gas cases).

The table below presents the modeling results from the four different meteorological data scenarios and the highest emission rate of the six operating modes. The operating mode resulting in the highest emission rate is listed in the “Scenario” column in the table below:

Toxic Air Pollutant	Averaging Period	ASIL[a] (µg/m³)	Modeled Concentration[b] (µg/m³)				Scenario
			SEA	L+SEA	TCM	L+TCM	
7,12-Dimethylbenz(a)anthracene	Annual	1.41E-05	4.00E-08	4.00E-08	3.00E-08	3.00E-08	Liquefying Case 3
Ammonia	24-hour	70.8	1.1	1.1	1.2	1.2	Vaporizing + Transfer Case A2
Arsenic	Annual	3.03E-04	4.40E-07	4.40E-07	4.30E-07	4.30E-07	Liquefying Case 3
Cadmium	Annual	2.38E-04	2.41E-06	2.41E-06	2.34E-06	2.34E-06	Liquefying Case 3
Chromium(VI)	Annual	6.67E-06	3.07E-06	3.07E-06	2.98E-06	2.98E-06	Liquefying Case 3
Hydrogen sulfide	24-hour	2	0.021	0.021	0.021	0.021	Liquefying Case 1
Sulfur dioxide	1-hour	660	26	26	20	20	Liquefying Case 1

[a] WAC 173-460-150
[b] Highest first high value for all receptors.
SEA = Meteorology from SeaTac
L+SEA = Meteorology from Tacoma South L and SeaTac
TCM = Meteorology from McChord
L+TCM = Meteorology from Tacoma South L and McChord

All meteorological scenarios show that the ambient concentration of all of the six pollutants are below their corresponding ASIL values when emitted at their highest rate.

Although not required of the source, PSE also conducted modeling on their criteria pollutant emissions as well, to determine if they were below the appropriate national ambient air quality standards (NAAQS) and Washington Ambient Air Quality Standards (WAAQS). The meteorological data discussed above was the same for this modeling analysis. The results of the model show predicted ambient concentration from the proposed project emissions are at or below the threshold values and acceptable source impact level (ASIL) for all pollutants.

The results of the modeling are presented below:

Criteria Pollutant	Averaging Period	NAAQS/ WAAQS (µg/m³)	Threshold Value[a] (µg/m³)	Modeled Concentration[b] (µg/m³)				Scenario
				SEA	L+SEA	TCM	L+TCM	
CO	8-hour	10,000	500	11	10	10	10	Vaporizing + Transfer Case B
	1-hour	40,000	2,000	25	25	25	25	Vaporizing + Transfer Case A2
SO_2	Annual	52	1	0.35	0.35	0.35	0.35	Liquefying Case 1
	24-hour	260	5	3.9	3.9	3.9	3.9	Liquefying Case 1
	3-hour	1,310	25	12	12	10	10	Liquefying Case 1
	1-hour	200	30	26	26	20	20	Liquefying Case 1
PM_{10}	Annual	--	1	0.017	0.017	0.016	0.016	Liquefying Case 3
	24-hour	150	5	1.2	1.2	1.1	1.1	Vaporizing + Transfer Case A2
$PM_{2.5}$	Annual	12	0.3	0.017	0.017	0.016	0.016	Liquefying Case 3
	24-hour	35	1.2	1.2	1.2	1.1	1.1	Vaporizing + Transfer Case A2
NO_2	Annual	100	1	0.043	0.043	0.042	0.042	Liquefying Case 2
	1-hour	188	7.5	5.9	5.9	5.9	5.9	Vaporizing + Transfer Case A2

[a] Cause or contribute threshold value from WAC 173-400-113, Table 4a. So long as the estimated worst case emissions are less than or equal to the threshold value, a facility is not considered to cause or contribute to an exceedance in a nonattainment area. The 1-hour NO_2 threshold value reflects the EPA's Interim 1-hour NO_2 Significant Impact Level.
[b] Highest first high value for all receptors.
SEA = Meteorology from SeaTac
L+SEA = Meteorology from Tacoma South L and SeaTac
TCM = Meteorology from McChord
L+TCM = Meteorology from Tacoma South L and McChord

Copies of all the dispersion modeling files and the modeling protocol are available upon request from the Agency.

I. APPLICABLE RULES & REGULATIONS

1. PUGET SOUND CLEAN AIR AGENCY REGULATIONS

SECTION 5.05 (c): The owner or operator of a registered source shall develop and implement an operation and maintenance plan to ensure continuous compliance with Regulations I, II, and III. A copy of the plan shall be filed with the Control Officer upon request. The plan shall reflect good industrial practice and shall include, but not be limited to, the following:
(1) Periodic inspection of all equipment and control equipment;
(2) Monitoring and recording of equipment and control equipment performance;
(3) Prompt repair of any defective equipment or control equipment;
(4) Procedures for startup, shut down, and normal operation;
(5) The control measures to be employed to ensure compliance with Section 9.15 of this regulation; and
(6) A record of all actions required by the plan.
The plan shall be reviewed by the source owner or operator at least annually and updated to reflect any changes in good industrial practice.

SECTION 6.09: Within 30 days of completion of the installation or modification of a stationary source subject to the provisions of Article 6 of this regulation, the owner or operator or applicant shall file a Notice of Completion with the Agency. Each Notice of Completion shall be submitted on a form provided by the Agency, and shall specify the date upon which operation of the stationary source has commenced or will commence.

SECTION 9.03: (a) It shall be unlawful for any person to cause or allow the emission of any air contaminant for a period or periods aggregating more than 3 minutes in any 1 hour, which is:
(1) Darker in shade than that designated as No. 1 (20% density) on the Ringelmann Chart, as published by the United States Bureau of Mines; or
(2) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in Section 9.03(a)(1).
(b) The density or opacity of an air contaminant shall be measured at the point of its emission, except when the point of emission cannot be readily observed, it may be measured at an observable point of the plume nearest the point of emission.
(c) This section shall not apply when the presence of uncombined water is the only reason for the failure of the emission to meet the requirements of this section.

SECTION 9.09: General Particulate Matter (PM) Standard. It shall be unlawful for any person to cause or allow the emission of particulate matter in excess of the following concentrations:
Equipment Used in a Manufacturing Process: 0.05 gr/dscf

SECTION 9.11: It shall be unlawful for any person to cause or allow the emission of any air contaminant in sufficient quantities and of such characteristics and duration as is, or is likely to be, injurious to human health, plant or animal life, or property, or which unreasonably interferes with enjoyment of life and property.

SECTION 9.13: It shall be unlawful for any person to cause or allow the installation or use of any device or use of any means designed to mask the emission of an air contaminant which causes detriment to health, safety or welfare of any person.

SECTION 9.15: It shall be unlawful for any person to cause or allow visible emissions of fugitive dust unless reasonable precautions are employed to minimize the emissions. Reasonable precautions include, but are not limited to, the following:
(1) The use of control equipment, enclosures, and wet (or chemical) suppression techniques, as practical, and curtailment during high winds;
(2) Surfacing roadways and parking areas with asphalt, concrete, or gravel;
(3) Treating temporary, low-traffic areas (e.g., construction sites) with water or chemical stabilizers, reducing vehicle speeds, constructing pavement or rip rap exit aprons, and cleaning vehicle undercarriages before they exit to prevent the track-out of mud or dirt onto paved public roadways; or
(4) Covering or wetting truck loads or allowing adequate freeboard to prevent the escape of dust-bearing materials.

REGULATION I, SECTION 9.20(a): It shall be unlawful for any person to cause or allow the operation of any features, machines or devices constituting parts of or called for by plans, specifications, or other information submitted pursuant to Article 6 of Regulation I unless such features, machines or devices are maintained in good working order.

2. WASHINGTON STATE ADMINISTRATIVE CODE

WAC 173-400-040(3): Fallout. No person shall cause or allow the emission of particulate matter from any source to be deposited beyond the property under direct control of the owner or operator of the source in sufficient quantity to interfere unreasonably with the use and enjoyment of the property upon which the material is deposited.

WAC 173-400-040(5): Odors. Any person who shall cause or allow the generation of any odor from any source or activity which may unreasonably interfere with any other property owner's use and enjoyment of his property must use recognized good practice and procedures to reduce these odors to a reasonable minimum.

WAC 173-400-040(6): Emissions detrimental to persons or property. No person shall cause or allow the emission of any air contaminant from any source if it is detrimental to the health, safety, or welfare of any person, or causes damage to property or business.

WAC173-400-111(7): Construction limitations.

(a) Approval to construct or modify a stationary source becomes invalid if construction is not commenced within eighteen months after receipt of the approval, if construction is discontinued for a period of eighteen months or more, or if construction is not completed within a reasonable time. The permitting authority may extend the eighteen-month period upon a satisfactory showing by the permittee that an extension is justified.

3. FEDERAL

<u>New Source Performance Standards : 40 CFR part 60</u>

<u>NSPS Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984</u>

This Subpart applies to all storage vessels with a capacity greater than or equal to 75 cubic meters (20,000 gallons) that are used to store volatile organic liquids unless otherwise exempted. One exemption (40 CFR 60.110b[b]) is for storage tanks with a capacity greater than or equal to 151 cubic meters (40,000 gallons) and that store a liquid with a maximum true vapor pressure of less than 3.5 kPa (0.5 psia). The LNG storage tank will have a working capacity of 8 million gallons (the only storage tank on site with a capacity of 20,000 gallons or more). By definition, the maximum true vapor pressure is the equilibrium partial pressure exerted by the VOCs in the stored volatile organic liquid. The partial pressure of the volatile components of LNG maintained at –260°F is less than 3.5 kPa (0.5 psia). Therefore, the Subpart Kb NSPS does not apply to the LNG storage tank.

The propane, iso-pentane, ethylene, and heavies storage tanks are exempt from Subpart Kb because their storage capacity is substantially less than 75 cubic meters (20,000 gallons). Tanks smaller than 20,000 gallons are not subject to this subpart.

NSPS Subpart LLL— Standards of Performance for SO2 Emissions From Onshore Natural Gas Processing for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011

This subpart applies to sweetening units and sweetening units followed by a sulfur recovery unit at onshore natural gas processing facilities.

§60.640 Applicability and designation of affected facilities.

(a) The provisions of this subpart are applicable to the following affected facilities that process natural gas: each sweetening unit, and each sweetening unit followed by a sulfur recovery unit.

(b) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with §60.647(c) but are not required to comply with §§60.642 through 60.646.

(c) The provisions of this subpart are applicable to facilities located on land and include facilities located onshore which process natural gas produced from either onshore or offshore wells.

(d) The provisions of this subpart apply to each affected facility identified in paragraph (a) of this section which commences construction or modification after January 20, 1984, and on or before August 23, 2011.

(e) The provisions of this subpart do not apply to sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere

The Tacoma LNG Project is not a natural gas processing facility. Therefore, the requirements of NSPS Subpart LLL are not applicable.

40 CFR 60 Subpart KKK - Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants

This subpart applies to affected facilities in onshore natural gas processing plants. This subpart defines natural gas processing plants as:

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

PSE LNG is not a natural gas processing plant and is therefore not subject to this subpart.

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NSPS Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

This subpart applies to stationary compression ignition internal combustion engines that are manufactured after April 1, 2006 and ordered after July 11, 2005. The Tacoma LNG Project will include a 1.5-MW diesel-fired emergency generator. This unit will be purchased as new for the Tacoma LNG Project and so the requirements of NSPS Subpart IIII relevant to emergency engines are applicable to the Tacoma LNG Project's emergency generator.

NSPS Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Production Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015

This subpart applies to certain equipment within the crude oil and natural gas source category that are constructed, modified, or reconstructed after September 18, 2015. The term crude oil and natural gas source category is defined in this rule as:

> (1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and
>
> (2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.

The term "local distribution company (LDC) custody transfer station" is defined as:

> A metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

As these terms demonstrate, Subpart OOOOa applies from natural gas wellhead to immediately upstream of the local distribution company custody transfer station. The Tacoma LNG Project is situated downstream of the local distribution company (i.e., PSE) custody transfer station. Therefore, NSPS Subpart OOOOa is not applicable to the Tacoma LNG Project.

National Emission Standards for Hazardous Air Pollutants: 40 CFR 63

NESHAP subparts HH and HHH: National Emissions Standards for Hazardous Air Pollutants for Oil and Natural Gas Production and Natural Gas Transmission and Storage

40 CFR 63 Subpart HH applies to gases up to the point of custody transfer at the production field where gases enter the pipeline for transmission. As the Tacoma LNG Project is well downstream of the point of custody transfer at the production field, this NESHAP does not apply.

40 CFR 63 Subpart HHH applies to natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major HAP sources. ***PSE Tacoma LNG is not a major source of HAPs and therefore this NESHAP does not apply.***

<u>Subpart Y: National Emissions Standards for Hazardous Air Pollutants for Marine Tank Vessel Loading Operations</u>

NESHAP Subpart Y requirements for marine tank vessel loading apply to area HAP sources with an initial startup date after September 20, 1999. However, this rule applies exclusively to marine tank vessel loading operations. The Tacoma LNG Project will only be fueling vessels, not filling tank ships or tank barges that transport bulk LNG. This subpart defines marine tank vessel loading operations as follows:

> *Marine tank vessel loading operation* means any operation under which a commodity is bulk loaded onto a marine tank vessel from a terminal, which may include the loading of multiple marine tank vessels during one loading operation. Marine tank vessel loading operations do not include refueling of marine tank vessels.

PSE Tacoma LNG is not engaged in a marine tank vessel loading operation and is not handling a commodity with a capot pressure greater than or equal to 10.3 kPa at standard temperature and pressure; therefore, the PSE Tacoma LNG Project will not be subject to this NESHAP.

<u>Subpart ZZZZ: National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines</u>

NESHAP Subpart ZZZZ for reciprocating internal combustion engines will apply to the Tacoma LNG Project's backup generator. Operation of the emergency generator will qualify under Subpart ZZZZ's provisions for emergency engines. Compliance with NSPS Subpart IIII requirements satisfies applicable Subpart ZZZZ requirements.

<u>Subpart JJJJJJ: National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources</u>

NESHAP Subpart JJJJJJ applies to area source boilers combusting certain types of fuel. Boilers burning exclusively natural gas are exempt from coverage and process heaters are not within the definition of boilers. ***Therefore, the Tacoma LNG Project's two heaters and LNG vaporizer, which are exclusively gas-fired, are not subject to this NESHAP.***

J. PUBLIC NOTICE

A notice of application was posted on the Agency's website for 15 days. No requests or responses were received during this time.

This project meets the criteria for public notice under WAC 173-400-171(3)(n). This section of the rule states *Any application or other action for which the permitting authority determines that there is significant public interest.* The agency believes there is a significant public interest in this project based on the amount of feedback, comments and general interest from both residents in the Tacoma area and others who have submitted questions and concerns about the PSE LNG project. As a result, this permit action will be going to public notice as outlined in WAC 173-400-171. The Agency also held two different public information meetings to allow citizens of the public to ask questions about the project and get a better understanding of how the permitting process works on 11/27/17 at 7:00pm, and another on 12/1/17 at 10:00am.

The public notice period will begin xx/xx/xxxx with a public hearing scheduled for xx/xx/xxxx.

K. RECOMMENDED APPROVAL CONDITIONS

Standard Conditions:

1. Approval is hereby granted as provided in Article 6 of Regulation I of the Puget Sound Clean Air Agency to the applicant to install or establish the equipment, device or process described hereon at the installation address in accordance with the plans and specifications on file in the Engineering Division of the Puget Sound Clean Air Agency.

2. This approval does not relieve the applicant or owner of any requirement of any other governmental agency.

Specific Conditions:

LNG Vaporizer

3. The LNG vaporizer approved under this order must comply with all applicable requirements established in 40 CFR Part 60, Subparts A and Dc.
    a. The owner and/or operator shall submit notification of the date of construction and actual startup, as provided by 40 CFR 60.7. This notification shall include:
        i. The design heat input capacity of the LNG Vaporizer and identification of fuels to be combusted.
    b. The owner and/or operator that combusts only natural gas shall record and maintain records of the amount of natural gas combusted during each calendar month.
    c. All records required under this section shall be maintained by the owner and/or operator of the LNG Vaporizer for a period of two years following the date of such record.

4. The LNG vaporizer shall only operate no more than 240 hours per any 12 consecutive month period.

5. The LNG vaporizer shall only use natural gas or boil-off gas as fuel for operation.

6. The LNG vaporizer shall not have a rated capacity to produce heat greater than 66 MMBtu/hr. This shall be documented in writing with manufacturer specification sheets or other agency approved method.

7. Within 60 days of commencing initial startup of the LNG vaporizer and then repeatedly once every 48 to 52 months of the previous test, the owner and/or operator shall conduct a performance test to verify compliance with the following emissions standards:
    a. 4.0 ppmv VOC @ 3% O_2 dry - VOC testing shall be conducted in accordance with EPA Test Method 25 or 25A or an alternative method approved by the Agency. Testing to quantify exempt compounds, such as methane, shall be conducted in accordance with EPA Test Method 18 or an alternative method approved by the Agency.
    b. 50.0 ppm CO @ 3% O_2 dry - CO testing shall be conducted in accordance with EPA Test Method 10 or an alternative method approved by the Agency.
    c. 9.0 ppmv NO_x @ 3% O_2 dry - NOX testing shall be conducted in accordance with EPA Test Method 7E or an alternative method approved by the Agency.

   The owner and/or operator shall conduct testing in accordance with Section 3.07 of Puget Sound Clean Air Agency (PSCAA) Regulation I using the following test Methods:

   Sampling sites and velocity traverse points shall be selected in accordance with EPA Test Method 1 or 1A. The gas volumetric flow rate shall be measured in accordance with EPA Test Method 2, 2A, 2C, 2D, 2F, 2G or 19. The dry molecular weight shall be determined in accordance with EPA Test Method 3, 3A or 3B. The stack gas moisture shall be determined in accordance with EPA Test Method.

   The LNG vaporizer is not required to commence initial startup for the sole purpose of conducting a performance test. The owner and/or operator may wait until the unit is needed to commence initial startup.

8. At least once per quarter during operation of the LNG Vaporizer, the Permittee shall conduct visual observations of the exhaust. If any emissions are visible from the exhaust, the Permittee shall conduct a visible emissions observation by a person certified in accordance with EPA Reference Method 9 (40 CFR 60, Appendix A). Such a test shall consist of a minimum of 30 minutes of opacity observations for the LNG Vaporizer. The owner and/or operator shall ensure 0% opacity from the LNG Vaporizer as measured with the Method 9.

9. Regardless of whether or not emissions are observed pursuant to Condition #8 of this permit, the Permittee shall conduct a minimum of one visible emissions test of the LNG Vaporizer each year (within 12 months) since the last visible emissions test required under this permit condition. Such a test shall consist of a minimum of 30 minutes of opacity observations of the LNF Vaporizer and shall be performed by a person certified in accordance with EPA Reference Method 9 (40 CFR 60, Appendix A). The owner and/or operator shall ensure 0% opacity from the LNG Vaporizer as measured with the Method 9.

Enclosed Ground Flare

10. The following processes shall have their vapor waste gases routed to the enclosed ground flare before being released to the atmosphere:

    a. Feed Gas Compressor
    b. Amine Pretreatment Unit
    c. Heavies Storage and fuel System
    d. Liquefaction
    e. Post Load Purge

11. The flare shall be continuously operating at all times that gases are routed to it. In the event that the flare goes out of service, either due to a malfunction or maintenance, all systems being routed to the flare shall shut down until the flare can be brought back into service.

12. The owner and/or operator shall operate the enclosed ground flare as outlined below:

    a. The enclosed ground flare shall be operated with a flame present at all times during normal operation. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.
    b. An owner/operator has the choice of adhering to either (i) or (ii) below
        i. Flares shall only be used meeting the heat content specifications in CFR 40 60.18 (c)(iii)(2) and the maximum tip velocity specifications in 40 CFR 60.18 (c)(4); or
        ii. Flares shall only be used that meet the requirements of 40 CFR 60.18 (c)(3)(i).
    c. The enclosed ground flare shall be designed for and operated with an exit velocity, as determined by the methods specified in 40 CFR 60.18 (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided below.
        i. The enclosed ground flare designed for and operated with an exit velocity equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) is allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf);
        ii. The enclosed ground flare designed for and operated with an exit velocity less than the velocity, V_{max} (as determined by the method specified in 40 CFR 60.18 (f)(5)) and less than 122 m/sec (400 ft/sec) are allowed.
    d. The owner and/or operator shall also install a continuous operating and recording temperature device in f the flare stack combustion zone.

13. The enclosed ground flare shall have a stack height of at least 105 feet above ground level and the inside diameter shall be no more than 6 feet at the exit.

14. The maximum H_2S and total sulfur content of the natural gas processed by the facility shall be limited to 0.25 grain of H_2S per one hundred cubic feet (gr/hcf). Compliance with this condition can be met by keeping tariffs which show the maximum allowed value of H2S in the pipeline which delivers the natural gas is 0.25 grain of H_2S per one hundred cubic feet (gr/hcf).

15. The owner and/or operator shall ensure the enclosed ground flare achieves a minimum of 99% destruction of all volatile organic compounds up to 3 carbons or less than 10 ppm NMOC by volume, dry basis as hexane @ 3% oxygen.

16. The enclosed ground flare may not discharge total sulfur dioxide (SO_2) into the atmosphere in excess of 165 lbs of SO_2 per MMScf. In lieu of conducting a performance test on SO_2 at the outlet of the flare, the Permittee may test the inlet concentration to the flare from the Amine pretreatment unit annually (Once every 12 months) for all sulfur containing compounds and then assume all sulfur converts to SO_2 in the stack.

    a. If the owner and/or operator decides to comply with this condition using the inlet SO2 concentration, the Inlet flare gas sulfur testing shall be at least once every 12 months (annually). The test sample should be a composite grab using an appropriate ASTM test method as specified in 40 CFR 75 Appendix D Section 2.3.3.1, or an alternative method approved by the agency. If, after two years of annual testing, the sulfur content is found to be consistently less than the 165 lbs of SO_2 per MMScf , the periodic sampling rate can be changed to once every 5 years.
    b. If the owner and/or operator decides to test the SO_2 at the outlet of the flare stack, the testing shall be done at least once every 12 months (annually). SO_2 testing shall be conducted in accordance with EPA Test Method 6C, or an alternative method approved by the agency. If, after two years of annual testing, the SO_2 emission rate is found to be consistently less than the 165 lbs of SO_2 per MMScf , the testing frequency can be changed to once every 5 years.

17. The enclosed ground flare may not discharge nitrogen oxides (NO_x) into the atmosphere in excess of the following limits: 0.066 lbs/MMBtu whenever the small warm burner (Burner 3) is operating, 0.060 lbs/MMBtu whenever the small cold burner (Burner 2) is operating, and 0.023 lbs/MMBtu whenever exclusively one or both of the large burners (Large Warm Burner 1 and Large Cold Burner 4) are operating.

18. The enclosed ground flare may not discharge carbon monoxide (CO) into the atmosphere in excess of the following limits: 0.196 lbs/MMBtu whenever the small warm burner (Burner 3) is operating, 0.180 lbs/MMBtu whenever the small cold burner (Burner 2) is operating, and 0.075 lbs/MMBtu whenever exclusively one or both of the large burners (Large Warm Burner 1 and Large Cold Burner 4) are operating.

19. There shall be no visible emissions from the enclosed ground flare, except for periods not to exceed 5 min in any 2 consecutive hours, as determined by EPA Method 22 in Appendix A in 40 CFR Part 60. The observation period shall be 2 hours and shall be used according to Method 22.

20. The owner and/or operator may not discharge Particulate Matter (PM) greater than 0.0075 lbs/MMbtu.

21. Initial compliance with the minimum destruction efficiency in Condition #15 must be demonstrated by testing the enclosed ground flare within 60 days of starting up the flare in accordance with Section 3.07 of Puget Sound Clean Air Agency (PSCAA) Regulation I using EPA reference methods 1, 2, 3C, 4

and 25C from Appendix A of 40 CFR Part 60. Inlet and outlet NMOC concentrations must be converted to ppmv of hexane. Compliance testing must be conducted while gas streams are being vented to the flare at a flowrate of at least 600 scfm or other flow rate that represents the worst case operating scenario and must consist of at least three separate 30-min test runs. The owner and/or operator may conduct additional testing in order to adjust the operating flare temperature required by Condition #28.

22. Initial compliance with the NOx limit in Condition #17 must be demonstrated by testing the enclosed ground flare within 60 days of starting-up the unit in accordance with Section 3.07 of PSCAA Regulation I using EPA reference methods 1, 2, 3A, 4 and 7E from Appendix A of 40 CFR Part 60. Compliance testing must be conducted while gas streams are being vented to the flare at a flowrate of at least 600 scfm or other flow rate that represents the worst case operating scenario must consist of at least three separate 30-min test runs.

23. Initial compliance with the CO limit in Condition #18 must be demonstrated by testing the enclosed ground flare within 60 days of starting-up the unit in accordance with Section 3.07 of PSCAA Regulation I using EPA reference methods 1, 2, 3A, 4 and 10 from Appendix A of 40 CFR Part 60. Compliance testing must be conducted while gas streams are being vented to the flare at a flowrate of at least 600 scfm or other flow rate that represents the worst case operating scenario must consist of at least three separate 30-min test runs.

24. Compliance with the visible emissions limit in Condition #19 must at a minimum be demonstrated by inspecting the enclosed ground flare stack for visible emissions once a week. These inspections must be performed during daylight hours when the flare system is in operation. If during the scheduled inspection or at any other time, visible emissions other than uncombined water are observed, the owner or operator must submit a report to the Agency within 30 calendar days of the end of the month in which the violation occurred. The report must include the time and duration of the visible emissions and a description of actions taken to correct the violation.

25. Compliance with the PM emission standard in Condition #20 shall be tested within 60 days of starting-up the unit in accordance with Section 3.07 of PSCAA regulation I using PSCAA method 5 (Board Resolution 540) or other agency approved method.

26. A testing notification must be submitted to the PSCAA in accordance with Section 3.07 of Regulation I, twenty one days before any compliance test required by this Order of Approval is conducted. The facility must submit a test plan with the notification that includes what operating scenario is being vented to the flare for each test and all specific flare and process equipment operating data that will be collected during the test as well as the methods that will be used to collect the data.

27. The enclosed ground flare is not required to be started up solely for the purposes of a compliance test within 60 days; the owner and/or operator may wait up to 180 days to conduct a performance test of this section.

28. The owner and/or operator shall operate the enclosed ground flare burners at or above the average temperature range recorded during the most recent source test which shows compliance with

Condition #15. The burner set point temperature of the flare, used to control the temperature within the flare, shall be set such that the temperature of the flare does not drop below the most recent source test temperature. The flare operating temperature requirement does not apply to periods of start-ups, shutdowns and/or malfunctions provided that these events are not actively processing waste gases and do not last for more than 1-hour.

29. The owner and/or operator shall report to the agency no later than 30 days after the violation is discovered all instances when either:

    a. The flare temperature readings were below the allowable temperature required under Condition #28.
    b. Startup, shutdown or malfunction events lasted longer than an hour and the enclosed ground flare was actively receiving waste gases.

30. The owner/or operator shall develop and maintain an Operation and Maintenance (O&M) plan for the enclosed ground flare. The O&M plan shall be developed and implemented per Agency's Regulation I. The following shall be included in the O&M plan at a minimum:

    a. Calibration, maintenance, repair and replacement procedures of monitoring, burner and ignition system equipment for the enclosed ground flare.
    b. Opacity inspection procedures.
    c. Written start-up, shutdown, and malfunction plan according to the provisions of 40 CFR 63.6(e)(3).

Fugitive Emissions (Leaks)

31. All valves, flanges, seals, joints and compressors shall be reasonably accessible for fugitive emissions monitoring during normal plant operation.

32. The owner and/or operator shall develop and maintain a Leak Detection and Repair Plan (LDAR) plan for fugitive emissions as outlined below. The LDAR plan shall be implemented and submitted to the agency for approval as soon as the facility is started up. If there are changes made after start-up or if the Agency has required changes to the LDAR as a result of the submittal, the owner and/or operator shall submit and implement the updated LDAR within 30 days of the changes. The LDAR plan shall be implemented using the provisions of 40 CFR 60 Subpart H, as outlined below:

    a. 40 CFR 63.160 Definitions
    b. General requirements under 40 CFR 63.162(a), (c), (d), (f), (g), and (h)
    c. Monitoring provisions for equipment gas/vapor and light liquid service under 40 CFR 63.163 to 174, using the 500-ppm leak rate definition immediately upon startup
    d. Method 21 test methods and procedures (40 CFR part 60, Appendix A)
    e. Delay of repair provisions under 40 CFR 63.171
    f. The alternative quality improvement program for equipment described in 40 CFR 63.175 and 176, in lieu of related 40 CFR 63.168 and 163 requirements.
    g. Recordkeeping provisions for equipment in VOC service under 40 CFR 63.181

General Plant Requirements:

33. The owner and/or operator shall document that the Liquefied Natural Gas storage tank capacity does not exceed 8 million gallons. The documentation shall be made readily available upon request from the Agency.

34. The owner and/or operator shall document and ensure that the LNG storage tank is cooled to at least -260 Degree F while storing natural gas. The documentation shall be made readily available upon request from the Agency.

35. The propane, isopentane, ethylene, and heavies storage tanks shall not be more than 20,000 gallons. The owner and/or operator shall document the tank capacities and the documentation shall be made readily available upon request from the Agency.

36. The refrigerant compressor shall be equipped with a seal leak recovery system capable of at least 90% recovery. This condition can be verified with testing or with manufacturer data information showing the system is capable of meeting 90% recovery on the refrigerant. The documentation to verify compliance with this condition shall be made readily available upon request from the Agency.

37. The owner and/or operator shall install a mercury removal system, capable of removing elemental mercury from the natural gas coming into the facility. The owner and/or operator shall include periodic inspection and maintenance of the mercury removal system in the operation and maintenance plan, accordingly.

38. The owner and/or operator shall document that the underground marine loading piping is vacuum jacketed and a fiber optic leak detection system is installed below the LNG lines to ensure there are no leaks while loading operations occur. The documentation showing compliance with this condition shall be made readily available upon request from the Agency.

39. The owner and/or operator shall keep documentation showing that the cooling water system is a closed loop system, and the water/propylene glycol mixture does not come into direct contact with any liquefaction equipment process liquid during operation. The documentation showing compliance with this condition shall be made readily available upon request from the Agency.

40. Pursuant to the State Environmental Policy Act, RCW 43.21C.060, WAC 197-11-660, and Puget Sound Clean Air Agency Regulation I, Section 2.12:

    The owner and/or operator shall ensure that the sole source of natural gas supply used in all operations at the Tacoma LNG facility comes from British Columbia or Alberta, Canada. Compliance with this condition shall be verified by the owner and/or operator maintaining the following records:

    a. Monthly records documenting the purchase of natural gas from seller(s) at the Huntingdon, B.C. Pool (trading hub) showing delivery point of the Huntingdon/Sumas interconnect with Northwest Pipeline and the corresponding monthly volume purchased.

b. Monthly records of nominations on Northwest Pipeline contracts showing receipt point of Sumas, delivery point of Frederickson and monthly volume of natural gas delivered.
c. Monthly records of nominations on the PSE system showing receipt point of Fredrickson, delivery point of Tacoma LNG facility and monthly volume of natural gas delivered.
d. Monthly records documenting the volume of natural gas received at the Tacoma LNG facility
e. Monthly records indicating that the flow of Natural Gas from Canada was from north to south passed the Fredrickson Gate Station.
f. In the event that the natural gas pipeline supplying the Tacoma LNG facility ceases to transport gas from north to south passed the Fredrickson Gate Station, the owner and/or operator shall immediately cease accepting natural gas from the pipeline.
    i. If the event described in Condition #40(f) of this order occurs, the owner and/or operator shall submit a report to the Agency no later than 15 days after original discovery outlining all of the following:
        1. Date and Time of incident.
        2. Owner and/or operators response to the incident.
        3. If the natural gas continued to be accepted during the event, provide reason(s) operations continued pulling natural gas from the pipeline.
        4. Measures taken to minimize the amount of natural gas taken from the pipeline during this time.
        5. Quantity of natural gas processed during the event.
g. The owner and/or operator shall submit semiannual data reports to the Agency compiling and summarizing the data recorded in Conditions #40 (a) – (f) of this order. These semiannual reports shall be submitted no later than January 31 and July 31 for each proceeding six month calendar period. If the issuance of this permit causes one of these reporting periods to be shorter than 6 months, the owner and/or operator shall submit data for the number of months it was operating before January 31 or July 31.

41. Odor Compliance
The owner and/or operator shall develop an odor response plan and odor complaint log with the following elements:
    a. Instances where the odor gas injection system (methyl mercaptan) caused odors and any corrective action taken.
    b. Initiate an investigation of all odor complaints received from the public as soon as possible, but no later than 12 hours after receipt of the complaint.
    c. Take corrective action to eliminate odors beyond the property line as soon as possible, but within 24 hours after receipt of the complaint. If the odors cannot be eliminated within 24 hours after receipt of the complaint, the owner and/or operator shall explain the reasoning in the odor compliant log and the date that it was corrected.
    d. Develop a report for every odor complaint and investigation. The odor complaint and investigation report must include the following:
        i. The date and time of when the complaint was received.
        ii. The date and time of when the investigation was initiated.
        iii. Location of complaint and investigation.

iv. Weather conditions during the complaint and investigation.
v. Description of complaint and investigation.
vi. Actions taken in response to the complaint.
vii. The date and time odors are no longer detected.

42. The owner and/or operator shall not perform truck loading for more than 360 hours per any 12 consecutive month period.

Recordkeeping and Reporting Requirements

43. All records required by this Order of Approval must be maintained onsite and available for inspection by agency personnel for at least two years from the date of generation.

44. The following records shall be kept onsite and up-to-date, and be made readily available to Agency personnel upon request at all times:

    a. Compliance test reports.
    b. Certified opacity readings for the LNG vaporizer and enclosed ground flare.
    c. Amount of hours of operation for the LNG vaporizer.
    d. Annual Sulfur sample readings and the dates the samples were taken.
    e. LDAR records outlined in the following sections of 40 CFR 63.181
        i. A list of all equipment subject to the LDAR program.
        ii. Maintain records of visual and Method 21 inspections of LDAR parts.
        iii. Maintain records when leak first detected, repair date, and reason for delay if not repaired within 15 days.
        iv. Maintain a list of equipment in organic service less than 300 hours per year
        v. Maintain records when leak first detected, repair date, and reason for delay if not repaired within 15 days.
    f. A copy of the odor complaint log and odor response plan.
    g. A log of the monthly and 12-month rolling total hours of truck loading operations.
    h. A written log showing corrective actions taken to maintain compliance with this Order of Approval. Each log entry must include date, time and description of the action.
    i. A written log showing any instance waste gases bypass the enclosed ground flare and are released to the atmosphere unabated. Each log entry must include date, time, duration and the estimated amount of waste gases (including all speciated data) released to the atmosphere.
    j. The Operation and Maintenance (O&M) plan.

45. The following records shall be kept onsite, updated within 30 days at the end of each month for at least two years from the date of generation, and be made readily available to Agency personnel upon request:
    a. Enclosed ground flare: Written or electronic copies of the 3-hour average readings for the flare operating temperature.
    b. Results of opacity inspections to determine compliance with the requirements in Condition #24.

46. The Agency shall be notified, in writing, within 30 days of the end of the month in which an exceedance of any emissions limitation and standard identified in these permit conditions is discovered.

L. CORRESPONDENCE AND SUPPORTING DOCUMENTS

M. REVIEWS

Inspector Review		Date:
Second Reviewer	Carole Cenci	Date: 6/14/19
Source Review	Keith Faretra	Date: 7/3/19