PUGET SOUND ENERGY

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May 25, 2018

BY U.S. MAIL AND EMAIL

Steven M. Van Slyke, P.E.
Director--Compliance
Puget Sound Clean Air Agency
1904 Third Avenue, Suite 105
Seattle, WA 98101

Re: Tacoma LNG Project SEIS Information Request Response

Dear Mr. Van Slyke:

Puget Sound Energy, Inc. (PSE) received your information request related to preparation of the Tacoma LNG Supplemental Environmental Impact Statement (SEIS) on May 7, 2018. As I noted in my May 8, 2018 email to Ms. Wheelock, no submittal date was specified in your request, but the SEIS Gantt chart that we were provided identified 20 days for our response. Therefore, consistent with that schedule, we are providing this timely response to your request.

PSE has completed a greenhouse gas (GHG) life-cycle analysis that concludes that the Tacoma LNG project will reduce GHG emissions by 14 to 15 percent as compared to the no action alternative (e.g., diesel fuel continues as the primary TOTE fuel). The very first question posed in your information request was whether PSE had performed a life-cycle analysis of its emissions. The answer to this question is "Yes." PSE's GHG life-cycle analysis was performed by a California-based consulting group with extensive experience conducting such analyses (Gladstein, Neandross & Associates or GNA). PSE took the additional step of engaging another team of experts on life-cycle analyses, particularly in relation to the maritime industry, to peer review the work performed by GNA. James Corbett and his team at Energy & Environmental Research Associates (EERA) conducted an independent evaluation of the GNA work product. The enclosed Background Information Document reflects this combined effort of PSE, GNA and EERA. This careful analysis documents that the total GHG emissions associated with the Tacoma LNG project are significantly lower than the total GHG emissions associated with the no action alternative.

Many of the other questions addressed to PSE in the information request relate to the proposed facility throughput and design. As is typical in such situations, there were refinements in design and process assumptions between the time that the FEIS was issued on November 9, 2015 and the time that the NOC application was submitted on May 22, 2017. The most significant changes from an emissions perspective were that the average daily production level was reduced from a daily average of 500,000 gallons/day to a daily average of 250,000 gallons/day and the flare system was consolidated from two flares to one flare. Those changed project characteristics were reflected in the NOC application and the attached Background Information Document. They should also form the basis of the SEIS.

PSE looks forward to sitting down with your team to discuss these responses and the associated GHG life-cycle analysis. Please let me know the earliest convenient time for us to do so. In the interim, if you have any questions please do not hesitate to contact me at (425) 456-2561.

Sincerely,

Keith Faretra

Attachments:

Response to SEIS Data and Information Request
Tacoma LNG Background Information Document

cc (by email):

Betsy Wheelock (BetsyW@pscleanair.org)
Jim Hogan
Lorna Luebbe
Tom Wood

Response to SEIS Data and Information Request
Puget Sound Energy for Tacoma LNG

May 25, 2018

Ecology and Environment, Inc. (E&E), supported by Life Cycle Associates, LLC (LCA), is preparing the life cycle greenhouse gas (GHG) emissions analysis in support of the Supplemental Environmental Impact Statement (SEIS) for the Tacoma Liquefied Natural Gas (LNG) project. By email dated May 7, 2018, Puget Sound Clean Air Agency (PSCAA), on whose behalf E&E/LCA is preparing the SEIS, provided Puget Sound Energy, Inc. (PSE) with a request for information. Each question presented in that request is reproduced in italics below, followed by PSE's answer.

General Questions

1. *If Puget Sound Energy (PSE) has completed a GHG life cycle analysis for the Tacoma LNG project, please provide the report and supporting documentation.*

    PSE completed a quantitative greenhouse gas (GHG) life cycle analysis for the Tacoma LNG project. Please see the attached document: "Tacoma Liquefied Natural Gas Project, Supplemental Environmental Impact Statement Background Information Document, March 30, 2018 (Revised May 25, 2018)" (BID). Supporting documentation is included with the BID.

2. *Please summarize all changes to the Tacoma LNG project construction activities, facility configuration, and operations since the FEIS was published.*

    Aspects of the Tacoma LNG project have changed since the FEIS was published. The final project is described in detail in the attached BID. Below is a summary of the changes that have occurred in regards to construction activities, facility configuration and operations since the FEIS was published:

    Construction:

    - The scope of the proposed construction as described in the FEIS remains materially the same. The changes outlined below have been made to the Tacoma LNG project since the FEIS was published but none are significant.
    - After the FEIS was completed, PSE stipulated to withdraw the construction of the new concrete barge pier on the Hylebos Waterway from the shoreline development permit.

Facility Operations:

- LNG production will be reduced to an average of 250,000 gallons per day (gpd), down from an average of 500,000 gpd (please refer to section 1.2.1.1 of the BID).
- The vaporizer will be limited to 240 hr/year for peak shaving supply production, down from 1,000 hr/year (please refer to section 1.3.4.1 of the BID)

Facility Configuration:

- The vaporizer has been redesigned (please refer to section 1.3.4.1 of the BID)
- The pretreatment heaters have been redesigned (please refer to section 1.3.3 of the BID)
- The flare system has been redesigned (please refer to section 1.3.4.3 of the BID)
- The backup generator specifications have changed (please refer to section 1.3.4.5 of the BID)
- As noted above, the Hylebos Waterway barge pier is no longer a component of the project.

Questions about the FEIS Emission Analysis

The FEIS provides emission estimates for project construction and project operation.

Construction Emissions (FEIS Appendix D-1)

Emissions of criteria pollutants and GHGs (methane [CH_4], nitrous oxide [N_2O], and carbon dioxide [CO_2]) were quantified for 2015, 2016, 2017, and 2018. For construction equipment, the analysis consists of listing the equipment type, count, number of months used, horsepower, load factor, utilization factor and emission factors (grams per horsepower per hour [g/hp-hr]). The emission factors are from the United States Environmental Protection Agency NONROAD model and are specific to Washington State. For GHGs, the fuel consumption is also provided. In the AR4 (the Intergovernmental Panel on Climate Change's fourth assessment report), Global Warming Potentials (GWPs[1]) are utilized to calculate carbon dioxide equivalent (CO_2e). Factors for workboats and tug/barge workboats are provided, but fuel consumption is not included.

1. *Is the equipment list (count, size, days, etc.) still accurate?*

   Yes, the construction equipment inventory is still accurate.

2. *Should the emission factors and fuel consumption values be updated to 2019–2022?*

   Whether the construction equipment emission factors should be updated is a decision to be made by PSCAA and its consultant(s). Any updates to the construction equipment emission factors would likely decrease the emissions impacts associated with the Tacoma LNG project as the result of stricter emission standards coming into effect.

[1] 25 for CH_4 and 298 for N_2O

3. *Will boats still be utilized in construction? If so, please provide fuel consumption estimates.*

   Two boats will still be utilized for the project. They are rated and utilized with these energy and operational parameters:

   - One personnel work boat with a 30 HP outboard engine will operate a total of 1,230 hours. The engine is expected to consume approximately 3.9 gal/hr of gasoline. This equates to approximately 4,797 gallons of gasoline over the construction phase.
   - One tug/work barge with two 250 HP diesel engines will operate a total of 420 hours. Each engine is expected to consume approximately 15.6 gal/hr of diesel. This equates to approximately 13,104 gallons of diesel over the construction phase.

The other portion of construction emissions consists of vehicle trips (workers and heavy-duty trucks). For these calculations, the winter and summer vehicle miles travelled (VMT) by workers and trucks were quantified for 2015–2018 and combined with emission factors from MOVES (g/minute). AR2 GWPs[2] *were used to calculate CO_2e. Workers were assumed to drive exclusively passenger cars.*

1. *Are VMT and worker/truck count estimates still accurate?*

   Yes, the VMT and worker/truck count estimates have not changed.

2. *Should workers drive a mix of light trucks and passenger cars? Is any carpooling anticipated?*

   PSE agrees that it is likely that workers could commute in a mix of light trucks and passenger vehicles.

   Yes, carpooling is anticipated; an existing mitigation measure under the FEIS was for PSE to encourage carpooling by construction workers.

3. *Should the emission factors/fuel consumption be updated to 2019–2022?*

   Whether the emission factors/fuel consumption for the construction worker vehicles should be updated is a decision to be made by PSCAA and its consultant. Any updates to the construction worker vehicle emission factors/fuel consumption would likely decrease the emissions impacts associated with the Tacoma LNG project as the result of stricter emission standards and higher vehicle efficiencies coming into effect.

[2] 21 for CH_4 and 310 for N_2O

4. *Provide the corresponding fuel consumption (diesel and gasoline) from MOVES or the relationship between CO_2 emissions and fuel.*

   PSE is not clear about what is being requested in this question. FEIS Appendix D-1 (Construction Emissions) documents the GHG emissions associated with construction worker vehicular commuting (assumed to be gasoline powered) as well as GHG emissions from heavy duty delivery trucks (assumed to be diesel powered). Emissions were calculated based on Vehicle Miles Traveled (VMT) and emission factors in grams per mile (g/m). There is obviously a relationship between CO_2 emissions and fuel in that the more fuel combusted, the greater the CO_2 emissions. However, we are not clear as to what is being requested given that the construction vehicle emissions (both worker vehicle and delivery vehicle) are calculated based on VMT and not fuel usage. The vehicle miles traveled (VMT) in the FEIS by both class of vehicles are still accurate.

5. *Shouldn't GWP values be switched to AR4 100-year values?*

   Whether the GWP values for the construction worker and heavy duty delivery vehicles should be updated is a decision to be made by PSCAA and its consultant(s). However, we note that in our life-cycle analysis in the attached BID we consistently used AR4 100-year values so as to be consistent with state and federal regulations. See, e.g., WAC 173-441-040(2); 40 C.F.R. § 98, Table A-1.

Source of Energy Inputs

The facility uses NG as an input along with electric power.

1. *What are the sources for NG (British Columbia, Rocky Mountains, etc.)?*

   As explained in Section 1.3.1 of the attached BID, all natural gas supplied to the Tacoma LNG project would come exclusively from British Columbia. No natural gas would be obtained from other regions for the Tacoma LNG project.

2. *Please provide any data to support the upstream emission estimates in GHGenius and GREET for NG production.*
   a. https://ghgenius.ca/
   b. https://greet.es.anl.gov/

   Due to the availability of specific regional data, as part of its GHG life cycle analysis PSE calculated the upstream emissions associated with natural gas production without reference to either GHGenius or GREET. Instead, as is explained in detail in Section 1.3.1 of the attached BID, PSE relied on emissions data specific to the natural gas sector provided by the Canada Science and Risk Assessment Directorate. GHG emissions data for the province of British Columbia were supplied. These data represent total emissions within the Province, including direct facility emissions at processing facilities and compression stations. Total natural gas production for British Columbia was taken from data reported by the Province in its Natural Gas & Oil Statistics data series. The gas production was then converted from billion cubic meters to an energy basis using an average gross heating value of 983 BTU/standard cubic foot (lower heating value basis) and 35.315 standard cubic feet per normal cubic meter. By dividing total GHG emissions by total natural gas production, we were able to derive emission rates unique to British Columbia and specific to natural gas production and processing, natural gas transmission and natural gas distribution. These emission rates are all presented in Section 1.3.1 of the attached BID.

Given these current, Province-specific data, PSE did not rely on GHGenius or GREET to derive emission factors or generate emissions estimates associated with natural gas production. This methodology was assessed in the peer review performed by Energy & Environmental Research Associates, LLC (EERA) and included as part of the attached BID. EERA stated that "We deem this approach and data reasonable for this analysis."[3]

We note that in April 2018 the Canadian government adopted new regulations applicable to the oil and gas industry including extraction, production and processing, and transportation of natural gas within that country. These new regulations, which begin phasing in before the Tacoma LNG Project will come on line, are anticipated to reduce methane emissions by 40 to 45 percent from 2012 levels by 2025. The emission reductions attributable to these new regulations, discussed in greater detail in Section 2.2 of the attached BID, were not taken into account in PSE's life cycle analysis. Therefore, PSE's life cycle analysis underestimates the benefits attributable to the Tacoma LNG Project.

3. *Is an estimate of NG used for transmission available?*

As part of its GHG life cycle analysis, PSE calculated the upstream emissions associated with natural gas transmission using GREET 2017 when specific regional information was not available. As described in response to the prior question, Province-specific emission factors were derived for transmission from well-head to the Huntingdon/Sumas export/import point. GHG emissions associated with natural gas transmission between the Huntingdon/Sumas hub and the PSE system are based on default compression/transport and fugitive emissions rates using GREET 2017, adjusted to reflect the use of electricity supplied from the Western Electricity Coordinating Council (WECC) grid mix. Please refer to Section 1.3.2 of the attached BID for the supporting data and the GREET 2017 default assumptions used in the upstream assessment. Given the information in GREET 2017, PSE did not estimate the specific amount of natural gas used for transmission and instead relied on the GREET emission factors for transmission.

[3] EERA Peer Review at 2.

4. *Are there contractual constraints on the mix of electric power used for the facility?*

PSE is not clear what information was being sought by this question. All electric power utilized by the Tacoma LNG project will be provided by Tacoma Power. That is the sole electrical utility that PSE has contracted with.

5. *What is the power generation mix from 2020 to 2040 for the utility that will provide power to the project?*

The fuel mix for Tacoma Power in 2016 is provided below (Washington Department of Commerce, October 2017). The utility's energy supply is nearly 97.5% emissions free. Energy supply is sourced from hydroelectric resources owned by Tacoma Power or purchased under contract from the Bonneville Power Administration (BPA). Tacoma Power is forecasting a continued decline in its load demand (a declining retail load forecast), which means that the utility can adequately supply its load balance with its owned hydroelectric resource and contracted supply that will track closely to the current resource mix. Please refer to section 1.3.5 of the BID for additional discussion. We note that the use of GREET 2017 to determine GHG emissions from Tacoma Power based on the utility's generation mix was assessed in the peer review performed by EERA. EERA stated that "We deem these to be appropriate emissions rates."[4]

Tacoma Power				
Utility Fuel Mix				
Fuel	Percent	MWh from Claims on Resources	Total MWh from Market Purchases	Total MWh
Biogas	0.00 %	0	0	0
Biomass	0.13 %	3,074	3,285	6,359
Coal	1.54 %	0	74,056	74,056
Geothermal	0.00 %	0	0	0
Hydro	84.23 %	3,948,832	95,984	4,044,816
Natural Gas	0.88 %	194	41,850	42,043
Nuclear	6.05 %	285,332	5,180	290,512
Other Biogenic	0.00 %	0	0	0
Other Non-Biogenic	0.04 %	0	1,744	1,744
Petroleum	0.02 %	0	1,098	1,098
Solar	0.00 %	0	0	0
Waste	0.00 %	0	0	0
Wind	7.11 %	341,423	0	341,423
Total	**100.00 %**	**4,578,855**	**223,197**	**4,802,051**

Operating Emissions (FEIS Appendix D-2)

Operating emissions are presented in Appendix D-2. Emissions from each piece of equipment are quantified. We have the following questions:

Is the basis for the operating emissions a 250,000 gallons per day (gal/day) or 500,000 gal/day plant?

The operating emissions calculations in the FEIS were based upon an average daily production rate of 500,000 gpd. However, as explained above, PSE is seeking

[4] EERA Peer Review at 5.

authorization in its Tacoma LNG NOC application to construct and operate a facility with an average daily production rate of 250,000 gallons. Consistent with the NOC application, the operating emissions in the attached BID are based on the design specifications for a facility with an average daily production rate of 250,000 gallons. PSE is no longer seeking authority to construct a 500,000 gpd facility. Please refer to section 1.2.1.1 of the BID for the discussion of the revised plant production rate.

Liquefier Operation

1. *What are the composition, density, storage temperature, and heating value of the LNG end product?*

The composition, density, storage temperature, and heating value of the LNG end product are shown below:

Storage Temperature	*F*	-258.8
Density	*lb/ft3*	27.14
Heating Value	*Btu/gal*	85,450.7

Composition (Mole Fraction)

Methane	0.967058
Ethane	0.021586
Ethylene	0.000000
Propane	0.004138
i-Butane	0.000503
n-Butane	0.000448
i-Pentane	0.000056
n-Pentane	0.000034
n-Hexane	0.000005
n-Heptane	0.000001
n-Octane	0.000000
Nitrogen	0.006122
Carbon Dioxide	0.000050
Water	0.000000
Hydrogen Sulfide	0.000000

2. *What is the composition of NG, and is it consistent with the CO_2 emission factors used in the FEIS?*

Information from Northwest Pipeline on the average composition of the natural gas it transported from British Columbia in 2017 is presented below. PSE does not anticipate any material change in the composition of the pipeline gas that would affect GHG emissions during the life of the project.

Composition (Mole Fraction)

Methane	0.913137
Ethane	0.060699
Propane	0.015437
i-Butane	0.002239
n-Butane	0.002415
i-Pentane	0.000476
n-Pentane	0.000341
Hexanes, plus	0.000299
Nitrogen	0.002717
Carbon Dioxide	0.002240
Water	0.000000
Hydrogen Sulfide	0.000000

The emissions factors used for estimating greenhouse gas emissions attributable to natural gas combustion are the EPA factors published in 40 C.F.R. § 98, Subpart C which assume a weighted US average composition/heating value. The FEIS and BID utilized the same emission factors.

3. *What is the power consumption per gallon of LNG for compressors and other facility power loa*ds?
    a. *Provide megawatts and throughput and range of kWh/gal of LNG if throughput is expected to change?*

The estimated power consumption per gallon of LNG produced is 1.35 kWh/gallon of LNG. See Section 1.3.5 of the attached BID for further discussion of the Tacoma LNG project electric energy consumption. LNG throughput is not expected to change.

Pretreatment Natural Gas Heater for Dehydrator Regeneration and Amine Reboiler

This is presumed to be a process heater fired by NG and boil off gas (BOG). Annual emissions are calculated assuming 8,760 hours/year and a firing rate of 8.5 MMBtu/hr. oxides of nitrogen (NO_X), volatile organic compound (VOC), and carbon monoxide (CO) are parts per million (ppm) values based on design specs. The CO_2, N_2O, and CH_4 emission factors are calculated from 40 Code of Federal Regulations (CFR) 98. AR4 100-year GWPs are used to calculate CO_2e.

1. *Is it appropriate to use 8,760 hours/year for this calculation? Since the NG supply pipe is the same pipe that re-gasified LNG flows through back to distribution, we know that 100% capacity factor isn't possible if any LNG will be re-gasified and sent back into NG distribution system or can you represent the energy use as a combination of MMBtu/hr combined with LNG production.*
    a. *For example, 8.5 MMBtu/hr x 24 hr/day / (250,000 gal/day x 85,000 Btu/gal) = 9,600 Btu/MMBtu, HHV.*

It is correct to ask whether it is appropriate to assume 8,760 hours per year of operations when estimating emissions from the 9.0 MMBtu per hour natural gas fired Water Propylene Glycol (WPG) heater and the 1.6 MMBtu/hr amine regenerator because under normal operating conditions there will be times during which these devices do not operate. Our purpose for selecting 8,760 hours was to demonstrate a worst-case scenario, consistent with standard air permitting requirements. We agree that this is an extremely conservative assumption.

2. *What are the potential to emit based on? 250,000 gal/day or 500,000 gal/day?*

All calculations in the NOC application as well as the attached BID are based on a maximum annual average production rate of 250,000 gal/day. That is the facility capacity for which an air permit is being sought.

3. *Do the emission factors for CO_2 used in the FEIS represent fully oxidized fuel or are these combustion emissions with the balance of carbon as CO_2, VOC, and CH_4?*

The FEIS and the attached BID utilized the default CO_2 factors published in 40 C.F.R. § 98, Subpart C which represent fully oxidized fuel.

LNG Vaporizer (Backup)

Emissions are calculated assuming 1,000 hours per year (hr/yr) and 28.5 MMBtu/hr of NG and BOG. Emission factors for NO_X, CO, and VOC are design specifications. The CO_2, N_2O, and CH_4 emission factors are calculated from 40 CFR 98. AR4 100-year GWPs are used to calculate CO_2e.

To clarify, fuel gas for the vaporizer is sourced from the facility fuel gas header. The primary fuel is pipeline gas. However, the fuel gas mix can include compressed boil-off gas (BOG) from the LNG tank. The vaporizer has been redesigned to 66 MMBtu/hr from 28.5 MMBtu/hr and will operate no more than 240 hr/year. Please refer to Section 1.3.4.1 of the attached BID for more details.

1. *Please describe the LNG vaporizer system – is the fuel used in a fired heat exchanger?*

The vaporizer is a water-bath, fire-tube type heater. Water/propylene glycol is circulated in the bath and transfers heat from the fire-tubes to the vaporizer tubes. LNG vaporization and LNG liquefaction are mutually exclusive operations; therefore the LNG vaporizer will not run concurrent with the other facility process heaters. Please see Section 1.3.4.1 of the attached BID for more details.

2. *Is 1,000 hours/year the anticipated amount of regasification activity? If so, how much LNG does this correspond to?*

No. Tacoma LNG is projected to regasify, at most, for 10 days per year. See, Section 1.3.4.7.2 of the attached BID. This corresponds to a maximum of 240 hours of regasification activity and approximately 10 million gallons per year of injection capacity. In Section 3.1 of the attached BID two scenarios are described for purposes of assessing different end use scenarios. The 10 million gallon/year figure was utilized for both scenarios.

3. *What is the throughput of LNG for 25 MMBtu/hr of vaporizer operation? Is the energy for vaporization a fixed Btu/Btu of LNG or does it depend on ambient temperature and flow rate?*

   Tacoma LNG is no longer anticipating use of a 28.5 MMBtu/hr vaporizer. The NOC application and the attached BID reflect that the vaporizer's maximum heat input capacity is now intended to be 66 MMBtu/hr. Regasification requires approximately 1,830 Btu per gallon of LNG throughput. We do not anticipate that this heat input requirement will materially change as a result of ambient temperature or flow rate; vaporization will only occur during the coldest periods.

4. *What are the power requirements for peak shaving in kWh/gal of LNG?*

   Regasification requires approximately 0.045 kWh/gallon of LNG regasified.

Enclosed Ground Flare

The FEIS accounts for 6 NG pilots firing a combined 0.39 MMBtu/hr for 8,760 hr/yr. The vent gas quantity is set at 10.2 MMBtu/hr with a 60% CO_2 content. The pilot GHGs are quantified along with the CO_2 in the vent gas. It is not clear that CO_2 from combustion of organics in the vent gas is quantified.

The flare system has been redesigned and now consists of a single enclosed ground flare; the information in the question above is no longer applicable. Please refer to Section 1.3.4.3 of the attached BID for a detailed description of the redesigned enclosed ground flare.

1. *Are pilot # and capacity still the same?*

   As noted above, the enclosed ground flare system has been redesigned as described in Section 1.3.4.3 of the attached BID. In calculating emissions from the enclosed ground flare the pilot fuel consumption was not broken out because we estimated emissions based on the assumption that the flare would run at its full heat input capacity for 8,760 hours per year. Based on this conservative assumption, the fuel consumption of the pilot is not relevant.

2. *Please provide spreadsheet of these calculations.*

   The requested spreadsheets are included as an attachment to the BID.

Emergency Flare

The FEIS accounts for 6 NG pilots firing a combined 0.39 MMBtu/hr for 8,760 hr/year. The vent gas quantity is set at 0.

As explained above, the design of the flare system has changed and there is no longer a separate emergency flare. The enclosed ground flare has been configured to handle emergency upset conditions. An emergency flare is not reflected in the NOC application. Please refer to Section 1.3.4.3 of the attached BID for more details about the flare system. Because the emergency flare is no longer part of the Tacoma LNG project design, answers to the questions relating to the emergency flare are neither necessary nor appropriate.

1. *Is it appropriate to set vent gas flowrate to emergency flare at 0?*

   N/A

2. *Are pilot # and capacity still the same?*

   N/A

3. *Please provide spreadsheet of these calculations.*

   N/A

Pretreatment Fugitives

1. *Please confirm that valve, PRV, pump seal, flange, and compressor seal counts are still correct.*

   An accurate inventory of all fugitive equipment leak components can be found in Section 1.3.4.4 of the attached BID. This represents the final design of the facility. We note that PSE's use of the inventory of fugitive leak components to quantify natural gas leak rates was deemed appropriate by EERA in its peer review document.[5]

2. *Storage tanks are listed, but have any losses associated with vapor transfer been quantified?*

   Yes. Losses associated with vapor transfer are quantified as a component of the fugitive emissions associated with the equipment components listed in the table found in Section 1.3.4.4 of the attached BID.

[5] EERA Peer Review at 5.

Emergency Generator

1. *Please confirm generator size at 1,600 kilowatts.*

   The emergency generator specifications have changed and PSE now intends to install a slightly smaller, 1,500 kilowatt, emergency generator. Please refer to Section 1.3.4.5 of the attached BID for more details about the emergency generator.

2. *Will fuel be diesel or NG?*

   The fuel employed by the emergency generator will be diesel.

3. *The top of the page says 500 hr/yr, but notes below say 100 hr/yr. Which is correct? Which was used in the calculations?*

   It is not clear from the question what page is being referenced. However, emissions from the emergency generator in the attached BID were calculated assuming a runtime of 500 hr/yr. This is an extremely conservative assumption and greatly overstates actual operation in a typical year (which is predicted to be 2 hours per month). Please refer to Section 1.3.4.5 of the attached BID for more details about the emergency generator.

4. *Is 7,000 Btu/bhp-hr accurate for engine efficiency? Does an average load factor need to be applied? What is the expected operation per year?*

   The facility proposes to install a 1,500 kW emergency generator. Emissions in the attached BID were calculated using the engine's ratings published at 100% output. The published fuel use consumption rate at this output is 104.6 gal/hr. As stated in Section 1.3.4.5 of the attached BID, under normal operating conditions the generator would only be used once per month for 2 hours of readiness testing for a total of 24 hours per year of operation.

Overall Mass Balance

The FEIS estimates emissions from several operating units. However, some of the emissions are bases on permitted operation.

1. *Please provide a table of energy inputs and emissions for a typical 250,000 or 500,000 gal/day operation showing:*
   - *NG input (MMBtu, lb) per day*
   - *LNG output (MMBtu, lb, gal) per day*
   - *Electric power input (kWh/day)*

   The following table provides the information requested above relating to natural gas input, LNG output and electrical power consumption.

Energy Input/Output: Based on 250,000 gal/day	Natural Gas Input	LNG Output	Electric Power
MMBtu / Day	22,745	21,363	
Pounds / Day	1,012,995	907,013	
kWh / Day			337,000

- *Fugitive emissions by source (kg/day)*

  Please refer to the spreadsheets included with the attached BID. These spreadsheets show fugitive emissions by source.

- *Mass balance of NG in and LNG out*
  - *How much CO_2 from the NG ends up in the clean-up system?*

    At the facility's base design feed gas concentration of 2 mol% CO_2, more than 99.76% of the CO_2 is removed by the pretreatment system {(1 – 0.00005*22.95 / 0.02*23.42)}. The CO_2 removed from the feed gas results in a less than 50 ppmv concentration in the liquefied stream.

  - *Is the difference between NG input and LNG output and fugitives combusted?*

    A portion of the extracted heavy hydrocarbons from the feed gas stream are captured and stored as liquid. The captured hydrocarbon liquid is removed from the facility by truck for reuse and recycling. As such, the difference in the natural gas input and the produced LNG is not entirely combusted. For the facility base design, 0.01 MMSCFD of extracted heavies will be captured and sold as fuel. This accounts for approximately 1.4% (volume) of the net material loss between the feed and what is liquefied {(0.01 / (23.55-22.84))}.

  - *Expected use of back-up and emergency systems.*

    As noted above and described further in Section 1.3.4.5 of the attached BID, under normal operating conditions the emergency generator would only be used once per month for 2 hours of readiness testing for a total of 24 hours per year of operation. Otherwise, back-up and emergency systems will only be utilized during power outage episodes caused by emergency situations. PSE anticipates that this will rarely occur given the redundant systems incorporated into the facility design.

Questions about the Project Reference Scenarios

The FEIS states that the LNG plant will produce 250,000 to 500,000 gal/day of LNG. The LNG will be stored in an 8-million gallon tank. There are four proposed uses for the LNG:

- *Re-gasify up to 1.1-million gal/day and inject back into distribution system for use by PSE customers.*
- *Sell 39 MGY to Totem Ocean Trailer Express (TOTE) Maritime for use in its two orca class ships that transport goods between the Port of Tacoma and the Port of Anchorage.*
- *Sell to bunker barges that will fuel other vessels in the port.*
- *Sell to tanker trucks for use as a substitute for diesel in heavy duty trucks or equipment.*

A life cycle emission analysis compares the emissions of each of these uses to a reference scenario, effectively expanding the boundaries of the FEIS analysis. Questions about each of these uses and their corresponding reference cases are provided below.

Regasification and Injection to PSE Distribution System

1. *The FEIS quantifies emissions associated with the regasification process.*

   This statement is accurate. However, updated and more detailed information about the Tacoma LNG facility regasification process are presented in the NOC application as well as Section 1.3.4.1 the attached BID.

2. *How much LNG will be re-gasified each year?*

   The maximum allowable production rate is limited to approximately 85,000 Dth/day (~1 million/day LNG) and regasification is not projected to occur more than 10 days per year (240 hours). Thus the maximum amount of LNG that would be regasified in a year would be no more than 10 million gallons.

3. *Is the amount projected to change over time?*

   No, this maximum production rate is not projected to change over time.

4. *What would the alternate supply of NG be in the absence of the LNG plant?*

   If the Tacoma LNG project does not occur then there is no alternate supply of natural gas from regasification. To meet initial customer demand for natural gas during those peak days, PSE would have to repurpose firm gas transmission from peak period electricity generation to residential gas service. In the absence of the Tacoma LNG Facility, during peak periods PSE would have to use this firm gas transmission to supply gas customers and thus would be required to operate "peaker" dual-fuel combustion turbine electric generating units utilizing fuel oil rather than using natural gas. In the absence of the Tacoma LNG facility, PSE would also immediately begin contractual negotiations for expansion of natural gas transmission infrastructure to ensure adequate transmission capacity at times of peak demand which would also likely lead to increased natural gas production during peak period due to the lack of natural gas storage. Further details about the impacts of the Tacoma LNG project not getting built can be found in Sections 1.3.6.2 and 4.0 of the attached BID.

- *Construction and operation of additional underground NG storage?*

  No. There is no ability to construct additional underground storage capable of supplying natural gas to the PSE service area. Existing underground storage in the Pacific Northwest (e.g., Jackson Prairie) does not have available additional capacity, and, even if additional capacity did exist, there is inadequate pipeline and compressor infrastructure to transport the natural gas from storage areas to PSE's service area on the days where peaking ability is necessary.

5. *If so, what is the venting/fugitive loss associated with storage?*

   As explained above, additional underground storage capacity that can be used to service PSE's customers during peak demand periods does not exist.

6. *What is the energy use associated with injection and withdrawal?*

   As explained above, additional underground storage capacity that can be used to service PSE's customers during peak demand periods does not exist.

7. *Would the NG continue to be sourced from BC/Alberta and the Rocky Mountains?*

   First, the proposed Tacoma LNG project is not sourcing any natural gas from Alberta or the Rocky Mountains. Second, the short term alternate source for natural gas during times of peak demand if the project does not go forward would be to repurpose gas currently imported from British Columbia and serve the excess gas demand with liquid fuels (as described in the answer to question 4 above). Longer term, if the project does not go forward, additional pipeline capacity, and likely additional production capacity, would be required to transport natural gas into PSE's service area during peak demand periods. Further details about the impacts of the Tacoma LNG project not getting built can be found in Sections 1.3.6.2 and 4.0 of the attached BID.

Sell LNG to Bunkering Barges

1. *Please provide annual amount to be sold to bunkering barges.*

   For purposes of performing its life cycle GHG analysis, PSE considered two different LNG consumption scenarios. These scenarios are defined in Section 3.1 of the attached BID. Scenario A assumes that all LNG is directed to on-site peak shaving and marine LNG bunkering supply at the Tacoma LNG Facility. Scenario B assumes a more diverse mix of end uses and assesses the utilization of the LNG tanker truck loading racks to supply LNG to Gig Harbor, on-road truck LNG fuel stations, and truck-to-ship bunkering. Please refer to Section 3.1 of the attached BID for more information about the two modeled scenarios.

2. *Please describe the vapor management system employed when transferring LNG into the barge fuel storage tanks.*

   Marine vessels would be bunkered with LNG for fuel using a dedicated marine bunkering arm equipped with a piggyback vapor return line. When connected to the receiving vessel, the LNG bunkering arm and connected piping would be purged with nitrogen, which would be routed to the enclosed ground flare. Once purged, LNG would be bunkered onto the receiving vessel at a maximum design rate of 2,640 gallons per minute. Once bunkering is complete, the liquid in the bunkering arm and in the adjacent piping would be drained back to the LNG storage tank. After draining, the arm and connected piping would be purged with nitrogen again. The purge would be routed to the enclosed ground flare and the arm/piping would be depressurized prior to disconnection.

   The LNG bunkering arm would be stored under a nitrogen atmosphere. The bunkering arm has the capability to return vapor from the receiving vessel to the LNG storage tank and/or to the enclosed ground flare. However, the LNG fuel tanks on the ships are designed to operate at 100 pounds per square inch (psi). LNG stored on the ship is subcooled and acts to collapse vapor pressure in the ship tanks during fueling (reducing the pressure). As a result, the vapor return system would not normally be used during bunkering. Please refer to Section 1.3.4.2.1 in the attached BID for more information about this system.

3. *Please provide the methane losses associated with fueling.*

   The methane losses associated with fueling have been calculated by PSE and are included in Section 1.3.4.2.1 of the attached BID. We note that the assumptions and methodology employed by PSE in calculating fueling emissions (both shore-to-ship and ship-to-ship) were assessed in the peer review performed by EERA and deemed appropriate.[6]

4. *Can it be assumed that the boats being fueled have the same vapor management system as the bunkering barge? If not, please describe.*

   Yes. That is an appropriate assumption.

[6] EERA Peer Review at 3.

5. *Please provide emission factors for the LNG engines (CO, VOC, CH_4, N_2O).*

   Emission factors for the LNG engines are provided in Section 1.3.6.1 of the attached BID.

6. *Please confirm that alternate propulsive system would be a new low NO_X engine operating on 1,000 ppm sufur fuel oil.*

   We do not believe that it is appropriate to assume, as the question does, that the alternate propulsion system for any vessel would be a new low NOx engine as opposed to an existing engine. For marine vessels to be compliant with the MARPOL regulations they will have either of two options available (neither of which would require the addition of NOx controls for existing engines):

   - Continue to use current engines in their current configuration utilizing compliant 0.1% sulfur fuel within the ECA or 0.5% sulfur fuel in the open ocean (from Jan 1st 2020).
   - Retrofit exhaust scrubbers to the vessel and continue to burn HFO.

   No existing vessel is required to replace its engines with new low NOx engines and it would likely be cost-prohibitive to do so.

7. *Please provide emission factors and fuel consumption for alternative diesel propulsion.*

   The emission factors and emission estimates associated with the vessels if they remain using diesel fuel are included in Section 1.3.6.1 of the attached BID.

Sell to Tanker Trucks

1. *Please provide the annual amount to be sold to tanker trucks.*

   For purposes of performing its life cycle GHG analysis, PSE considered two different LNG consumption scenarios. These scenarios are defined in Section 3.1 of the attached BID. Scenario A assumes that all LNG is directed to on-site peak shaving and marine LNG bunkering supply at the Tacoma LNG Facility. Scenario B assumes a more diverse mix of end uses and assesses the utilization of the LNG tanker truck loading racks to supply LNG to Gig Harbor, on-road truck LNG fuel stations, and truck-to-ship bunkering. Please refer to Section 3.1 of the attached BID for more information about the two modeled scenarios.

2. *Please describe the vapor management system employed when transferring LNG to tankers.*

   As described in the attached BID, each truck bay would have a liquid supply and vapor return hose. After truck loading, the liquid hose would be drained to a common, closed truck station sump connected to the Tacoma LNG Facility vapor handling system where it would be allowed to boil off and be re-liquefied or sent to the pipeline. Nitrogen would be used to purge the hoses and facilitate liquid draining and would then be routed to the enclosed ground flare. Further information about the tanker loading system can be found in Section 1.3.4.2.2 of the attached BID.

3. *Please provide the methane losses associated with fueling tanker trucks including trapped volume in fuel connections and vapor losses.*

   The methane losses for LNG transfers from the plant to tanker trucks are provided in the GHG spreadsheets included with the attached BID. A hose will be used to capture the volatile emissions from vapor displacement during tanker truck loading. The fugitive losses associated with this system operation are inherent to the equipment components listed in the table found in Section 1.3.4.4 of the attached BID. The emissions captured by the hose during truck loading will be sent preferentially to the BOG handling system or to the flare.

4. *Note that the California Air Resources Board (CARB) assumes and Energy Economy Ratio (EER) of 0.9 as an efficiency comparison for LNG vehicles compared to diesel vehicles and also has emission factors for diesel and LNG vehicles. Is the CARB assessment reasonable? https://www.arb.ca.gov/fuels/lcfs/092309lcfs_lng.pdf with data in the CA_GREET model. If you have more accurate data, please:*
   a. *Provide the vapor management system employed for fueling LNG heavy duty trucks.*
   b. *Provide the difference in efficiency between this diesel engine and the LNG engine.*
   c. *Provide emission factors for the truck LNG engines (CO, VOC, CH_4, N_2O).*
   d. *Confirm that alternate propulsive system would be a new low NO_X engine operating on ULSD.*

   Section 1.3.6.4 of the attached BID evaluates the emissions associated with on-road diesel v. on-road LNG combination tractor operations. In performing our life cycle analysis, PSE employed GREET 2017 default values for downstream emissions from LNG combination tractor operation after the proposed Tacoma LNG project. For purposes of comparison to a baseline No Project condition, Well-to-Wheels emissions rates were also estimated for a diesel-fueled combination tractor. The resulting emissions rates are summarized in Section 1.3.6.4 of the attached BID.

   These emissions rates are provided on a g/MMBTU of fuel delivered to the vehicle. Based on GREET 2017 default assumptions, the natural gas combination tractor has a 10% efficiency penalty relative to the diesel tractor, meaning that the natural gas tractor will consume 10% more energy per mile of operation than the diesel tractor.

   We do not believe that the assumption in “d” is an appropriate assumption as diesel-fuel combination tractors have a long lifetime and there is no basis to assume that if the

Tacoma LNG project does not occur, the tractor owners will all replace their existing vehicles with new tractors possessing low NOx engines.

PUGET SOUND ENERGY

Background Information Document

March 30, 2018

(Revised May 25, 2018)

1.0 DESCRIPTION OF PROPOSED ACTION

1.1 Introduction

Puget Sound Energy, Inc. (PSE) is the proponent of the Proposed Action, which consists of the construction, operation, and decommissioning of the Tacoma Liquefied Natural Gas (LNG) Facility (Project). PSE is a corporation organized under the laws of the State of Washington. The company is a Washington-regulated utility serving approximately 1.1 million electric customers and over 800,000 natural gas customers in 10 counties across the state.

On November 9, 2015, the City of Tacoma issued a Final Environmental Impact Statement (FEIS) for the Project.

On May 22, 2017, PSE submitted a Notice of Construction (NOC) permit application for the Project to the Puget Sound Clean Air Agency (PSCAA). In January 2018, PSCAA concluded that a Supplemental Environmental Impact Statement (SEIS) was necessary to quantitatively assess the Project's greenhouse gas (GHG) emissions throughout the fuel life cycle, to supplement sections 3.2 and 3.13 of the FEIS.

1.2 Proposed Action Components

The proposed Project components considered in the SEIS are the Tacoma LNG Facility and the associated Totem Ocean Trailer Express (TOTE) Marine Vessel LNG Fueling System. All components are subject to numerous applicable regulations. The main components of the Project are described below.

1.2.1 Tacoma LNG Facility

1.2.1.1 Overview

The Tacoma LNG Facility is fully described in the FEIS and the NOC permit application. As originally assessed under the FEIS, the Tacoma LNG Facility would have had the capacity to produce an average of 500,000 gallons per day of LNG. PSE opted to pursue construction approval from the Agency for a facility with the capacity to produce an average of 250,000 gallons of LNG per day (actual daily maximum production varies depending on conditions such as ambient temperature). As the nature of the Tacoma LNG Facility or its intended uses has not changed, the focus of this document is on the components relevant to the fuel life-cycle analysis.

The LNG would be stored in the Tacoma LNG Facility LNG storage tank before being transferred to TOTE's ships via cryogenic pipeline as part of the TOTE Marine Vessel LNG Fueling System. LNG could also be transported from the Tacoma LNG Facility by tanker trucks or reinjected into the local distribution network to meet peak natural gas demand. The Tacoma LNG Facility would operate and be staffed with approximately 16 to 18 full-time employees 24 hours per day, 365 days a year.

PSE staff would also be responsible for operating and maintaining the LNG pipeline and fuel loading equipment that would be located at TOTE's terminal. Maintenance and operating protocols would be developed taking into account federal and state regulations, PSE policies and practices, and best industry practices. Additionally, PSE would contract for security service as required to meet regulatory requirements.

The proposed Tacoma LNG Facility site plan is presented in Figure 1 and the proposed process flow diagram is presented in Figure 2. Additional details about the layout of the various components proposed at the Tacoma LNG Facility are discussed in the NOC permit application.

1.3 Components of the Life Cycle Analysis

The proposed components considered in the SEIS life cycle analysis covers each stage of fuel handling including extraction, transmission, liquefaction, loading and end use. This fuel life cycle would include a variety of discrete components further described in this section.

1.3.1 Natural Gas Production

The gas supply for the Project would come exclusively from British Columbia. No natural gas would be obtained from other regions for the Tacoma LNG Facility. British Columbia has adopted comprehensive drilling and production regulations that reduce methane emissions. The Canadian national government has recently adopted new regulations that require companies to control methane leaks from equipment and the release of methane from compressors starting on January 1, 2020. The Canadian national government also adopted regulations to take effect on January 1, 2020 limiting methane leaks associated with well completion but noted that such requirements are already in effect in British Columbia. The Canadian national government further adopted regulations to take effect on January 1, 2023 that will control methane venting and the release of methane from pneumatic devices. British Columbia is only allowed to deviate from these federal requirements if it can demonstrate that its local program results in equivalent or better methane reductions. These requirements are further discussed in Section 2.2 below. The life cycle analysis presented in this document takes into account only those British Columbia regulations currently in effect and does not consider the additional benefits that will result from the new national regulations adopted by the Canadian government in April 2018. Thus, Project GHG emissions will be even lower than projected in this document as a result of the new national regulations.

GHG emissions estimates for natural gas production in British Columbia are taken from a customized extract of Province-specific data from the National Inventory Report (NIR). The NIR is Canada's official inventory of GHG emissions and is subdivided by geography, industry, and economic sector. GHG emissions specific to British Columbia are provided in Table A12-11 of the 2017 NIR. Unfortunately, this table aggregates emissions from oil and natural gas processes and prevents estimates of emissions specific to natural gas transmission only. To better account for natural gas-related emissions, an inquiry was sent to the Canada Science and Risk Assessment Directorate requesting emissions data for the natural gas sector only.

Table 1 summarizes the relevant data from Table A12-11 of the NIR and the natural gas-only data request to the Canadian government.[1]

Table 1. BC Province GHG Emissions (National Inventory Report, 2017)

BC Province 2017 NIR: Table A12-11	**Oil and Natural Gas (million tonnes CO2e)**						**Natural Gas Only (kilotonnes)**		
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**CO_2 (2015)**	**CH_4 (2015)**	**N_2O (2015)**
Natural Gas Production and Processing	10.4	11.7	11.8	12	12	10.9	9,072	68.5	0.24
Oil and Natural Gas Transmission	1.1	1.1	1	1.4	1.2	1.5	1,239	8.9	0.03
Natural Gas Distribution	0.1	0.1	0.1	0.1	0.1	0.1	14.7	3.4	0.00
Total	11.6	12.9	12.9	13.5	13.3	12.5	10,326	80.9	0.27

The GHG emissions data presented for British Columbia represent total emissions within the Province, including direct facility emissions at processing facilities and compression stations. Because the vast majority of British Columbia's electrical energy is supplied from hydropower and would not have indirect GHG emissions associated with the electrical energy production, it is assumed that the direct facility emissions totals are a reasonable representation of total emissions associated with natural gas production and transmission in the Province.

Total natural gas production for British Columbia is taken from data reported by the Province in its Natural Gas & Oil Statistics data series.[2] Table 2 summarizes the production data from gas processing plants. This volume represents the marketable gas produced in the Province, after accounting for shrinkage in the processing plants.

Table 2. Natural Gas Production and Export Volumes for British Columbia

BC Gas Production Volumes and Export Volumes ($1000\ m^3$)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Residue Gas Plant Outlet - BC Production Only	29,808,782	35,572,183	35,723,237	38,663,739	41,241,670	43,339,421

The gas volume of 43.3 billion cubic meters is converted to an energy basis using an average gross heating value of 983 BTU/standard cubic foot (lower heating value basis) and 35.315

[1] Communications with Frank Neitzert, Chief, Energy Section – Canada Science and Risk Assessment Directorate. February 2018.

[2] Production and distribution of Natural Gas in B.C. Available at https://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/statistics

standard cubic feet per normal cubic meter. Expressed in energy terms, British Columbia's total natural gas production for calendar year 2015 was 1.505 trillion MMBTU.

Normalizing the total GHG emissions in Table 1 by the total natural gas production yields the emissions rates summarized in Table 3. Natural gas transmission in British Columbia would occur between gas processing facilities and the Huntingdon/Sumas hub. The natural gas would not travel on distribution systems within the Province. Therefore, GHG emissions within British Columbia attributable to natural gas sourced for the proposed project should not include "Natural Gas Distribution" emissions.

Table 3. 2015 GHG Emissions Rates for Natural Gas Production, Transmission, and Distribution in British Columbia

BC Natural Gas GHG Emissions (grams/MMBTU)	CO_2	CH_4	N_2O	CO_2e
Natural Gas Production and Processing	6,030	45.5	0.16	7,216
Oil and Natural Gas Transmission	824	5.9	0.02	978
Natural Gas Distribution	10	2.3	0.00	67
Total	6,863	53.7	0.18	8,260
Total Ex-Distribution	6,853	51.5	0.18	**8,193**

1.3.2 Natural Gas Transmission & Delivery

The gas supply for the Project would be transported from British Columbia by way of Westcoast Pipeline and the Huntingdon/Sumas export/import point. Gas received at the Huntingdon/Sumas export/import point is transported approximately 145 miles on Northwest Pipeline to the Frederickson Meter Station. PSE has acquired pipeline capacity that would be dedicated to this purpose.

The bulk of gas receipts into the PSE system for Tacoma LNG are anticipated at Frederickson. Some gas may enter the PSE system at the North Tacoma Meter Station, approximately 131 miles from the Huntingdon/Sumas hub, under certain conditions. However, to be conservative, the longer transmission distance of 145 miles is assumed for all gas transmission between the Huntingdon/Sumas hub and the PSE system.

GHG emissions associated with natural gas transmission between the Huntingdon/Sumas hub and the PSE system are based on default fugitive methane emissions rates and compression/transport emissions rates in GREET 2017, adjusted to reflect the use of electricity supplied from the Western Electricity Coordinating Council (WECC) grid mix. The default rates for fugitive methane emissions are conservative as they represent a national average derived from the US EPA's national GHG inventory. Prior studies have indicated that the natural gas transmission system in the Pacific Northwest has lower fugitive emissions rates than the national average, owing partly to the relatively younger age of the Pacific Northwest system compared to older systems in other parts of the country.[3] Emissions rates derived from GREET 2017 for

[3] The relevant pipe is located in the corridor from Sumas south to Frederickson. There is no mainline pipe in that route older than the 1970s, with most pipe installed in the 1990s and in 2006. The 1956 26" pipe which ran from Sumas to the Columbia river in western Washington

(continued . . .)

species that are assigned a Global Warming Potential (GWP) factor, or whose subsequent oxidation in the atmosphere to CO_2 would contribute to the GHG inventory, are summarized in Table 4.

Table 4. Per-mile GHG Emissions Rates for Natural Gas Transmission (GREET 2017)

Washington State Gas Transmission (g/MMBTU-mile)	VOC	CO	NOx	BC	OC	CH_4	N_2O	CO_2
Pipeline Compression / Transport	0.006	0.029	0.035	0.000	0.000	0.029	0.002	2.61
Methane Leakage						0.066		

Energy-specific emissions rates are calculated by applying the emissions rates in Table 4 to the 145-mile transmission distance from the Huntingdon/Sumas hub to the PSE system. The resulting energy-specific emissions rates are summarized in Table 5. The loss factor for this portion of the fuel pathway is 0.048%.

Table 5. GHG Emissions Rates for Natural Gas Transmission (GREET 2017)

Washington State Gas Transmission (g/MMBTU)	VOC	CO	NOx	BC	OC	CH_4	N_2O	CO_2
Pipeline Compression / Transport	0.826	4.24	5.03	0.002	0.004	4.17	0.295	377
Methane Leakage	0.000	0.00	0.00	0.000	0.000	9.51	0.000	0.0
Total	0.826	4.24	5.03	0.002	0.004	13.68	0.295	377

Once the natural gas is received into the PSE system, it is transported to the liquefaction facility. PSE has calculated its Lost and Unaccounted For Gas at 0.095% of total system receipts. Actual fugitive methane emissions from the PSE system will be only a portion of this value, but because PSE does not directly measure or calculate total fugitive emissions separate from its Lost and Unaccounted For Gas values, a methane leak rate of 0.095% is conservatively used. This translates to a methane emissions rate of 19.19 gCH_4/MMBTU of natural gas throughput.

1.3.3 Natural Gas Pretreatment, Conversion & Storage

Natural gas would enter the Tacoma LNG Facility through the metering and odorant area. A single underground pipeline would connect the Tacoma LNG Facility to PSE's natural gas

(. . . continued)
was retired in 2006. Based on an analysis of data from PHMSA's 2017 Annual Report for Gas Transmission Systems (https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids), the average age of transmission pipeline installed in the US is 1968-1973, implying that the pipeline segment relevant to the Tacoma LNG project is significantly newer than the national average.

distribution system. Metered natural gas entering the Tacoma LNG Facility for liquefaction would be first routed to an inlet filter separator to remove small particles and liquid droplets to protect downstream boost compression and the pre-treatment system. The feed gas would be boosted in pressure to approximately 525 psig by an electric motor-driven, two-stage, integrally geared centrifugal compressor. Fugitive leakage from the feed gas compressor's seals would be captured and sent to the enclosed ground flare.

1.3.3.1 Amine Pretreatment System

Natural gas entering the Tacoma LNG Facility will be composed primarily of methane, but will also contain ethane, propane, butane, and other heavy end hydrocarbons. In addition, quantities of nitrogen, carbon dioxide (CO_2), sulfur compounds (H_2S and odorants), and water will be present in the feed gas stream entering the plant.

CO_2 and water would freeze within the liquefaction process and must be removed to sufficient levels to avoid riming of the platefin heat exchangers. CO_2, water, some sulfur based components and trace contaminants would be removed from the feed gas by an Amine Pretreatment System. The Amine Pretreatment System will be designed to treat up to 26 million standard cubic feet per day (MMscfd) of inlet gas with a 2 percent CO_2 concentration so as to not limit the capacity of the liquefaction system.

For purposes of determining GHG emissions from the Tacoma LNG Facility, the Amine Pretreatment System generates GHGs from two components of the process. First, there is a 9.0 MMBtu per hour natural gas fired Water Propylene Glycol (WPG) heater which would generate combustion emissions. Second an aqueous amine solution would absorb CO_2 and hydrogen sulfide (H_2S) from the natural gas through a chemical reaction, resulting in a "sweet" gas with less than 50 parts per million (ppm) of CO_2 and a "rich" amine solution that contains the CO_2 and H_2S. The "rich" aqueous amine solution would then be heated in a 1.6 MMBtu/hr regenerator to remove the CO_2 and H_2S, resulting in a "lean" amine solution that would be reused in the process. The exhaust from the amine regenerator would be routed to the enclosed ground flare which would oxidize H_2S, odorants, and volatile organic compounds (VOCs) at high temperature into water, CO_2, and sulfur dioxide (SO_2).

1.3.3.2 Heavy Hydrocarbon Removal

After pretreatment, but prior to liquefaction of the natural gas, heavy hydrocarbons that may freeze at the cryogenic temperatures encountered downstream would be removed by partial refrigeration. A portion of the removed hydrocarbons would be stored as a liquid at ambient temperature on site in a horizontal pressure vessel and periodically trucked off site for use as fuel and displacing other fossil fuels. Nitrogen would be used to purge the truck loading hoses and facilitate liquid draining and then be routed to the enclosed ground flare. The remainder of the removed hydrocarbons would either be used as fuel gas on site or disposed of via the enclosed ground flare. Flash gases from the heavy hydrocarbon storage vessel would be sent to the enclosed ground flare.

1.3.3.3 Liquefaction

After the heavy hydrocarbon removal process, the natural gas would be mixed with compressed boil-off gas (BOG) and condensed to a liquid by cooling the gas to approximately –260 degrees Fahrenheit (°F) in a brazed aluminum heat exchanger using a mixed refrigerant (composed of methane, ethylene, propane, isopentane, and nitrogen). Compressor seal leakage would be captured and sent to the enclosed ground flare. Liquefaction is expected to typically occur during 51 weeks of the year. Up to 10 days per year, the Tacoma LNG Facility is expected to operate in a holding mode while LNG is vaporized.

1.3.3.4 LNG Storage

The LNG would be stored in an 8 million gallon (net), low-pressure LNG storage tank at less than 3 psig. The LNG storage tank would be a full containment structure consisting of a steel inner tank and a pre-stressed concrete outer tank. The storage tank would be vapor- and liquid-tight without losses to the environment. Insulating material would be placed between the inner and outer tanks to minimize heat gain and boil-off.

The temperature of the LNG would be maintained below –260°F to keep the treated natural gas in a liquid state using an auto-refrigeration process. Inside the tank, vapor pressure above the liquid is kept constant so the temperature is maintained. When LNG temperature increases, vapors are created from the boiling liquid (i.e., BOG). In order to avoid pressure build-up within the tank, BOG would be collected in the BOG Recovery System. The BOG Recovery System would warm the gas and boost its pressure for either re-liquefaction and return to the storage tank or reinjection into the distribution system as natural gas. In the highly unlikely event that a process upset situation occurs, excess LNG vapors would vent to the enclosed ground flare.

1.3.4 LNG Product Delivery

LNG would be pumped out from the Tacoma LNG Facility's storage tank for either (a) vaporization and reintroduction into the local distribution system, or (b) use as marine vessel or surface vehicle fuel. LNG would be removed from the storage tank by way of submerged motor in-tank pumps. The submerged motor LNG pumps would be contained within the enclosed LNG tank and therefore are not a source of fugitive emissions.

1.3.4.1 LNG Vaporization

The LNG vaporization system would produce natural gas for customers connected to PSE's existing distribution system during peak demand periods. This is commonly referred to as peak shaving. The vaporizer would use a natural gas-burning, fire-tube type water heater. The heated water and propylene glycol mixture would be used to vaporize LNG to a gaseous state. The vaporizer would use an ultra-low nitrogen oxides (NO_X) burner that would have a maximum design heat input capacity of 66 MMBtu per hour. The vaporizer burner would produce emissions from natural gas combustion. The Tacoma LNG Facility would use the vaporized LNG and BOG for fuel as much as possible. However, when those fuels are not available, natural gas from the pipeline would be used as fuel. As a conservative approach for the emissions calculations, PSE assumed all combustible waste gases generated on site are sent to the enclosed ground flare and all process equipment fuel demand is met using natural gas from the pipeline. This approach overstates GHG emissions from the LNG vaporization system.

The vaporization system would have the capacity to deliver 66,000 MMBtu per day (66,000 dekatherms/day or approximately 64.2 MMscfd) of vaporized natural gas at a temperature of 65°F and a pressure range between 150 psig and 249 psig to the metering area. An odorizer would add odorant to the natural gas before it enters the distribution system. PSE estimates that the vaporization system would operate for up to 10 days per year during peak natural gas usage times in the winter months. In addition, during these periods of vaporization, TOTE would be supplied with PSE's stored LNG and the natural gas supply intended for liquefaction for TOTE and others would be diverted to other parts of the PSE system providing an additional 19,000 MMBtu per day of peaking. So, in total, the Project provides up 85,000 MMBtu per day of natural gas to meet peak need for a period of up to 10 days.

1.3.4.2 Marine Vessel Fuel

1.3.4.2.1 Marine Bunkering

The LNG would be conveyed via cryogenic pipeline to the TOTE Marine Vessel LNG Fueling System. The LNG pipeline would extend 1,200 feet from the Tacoma LNG Facility storage tank, traveling below the Alexander Avenue right-of-way, above ground along the TOTE terminal access trestle, and end at a loading arm on a bunkering platform in the Blair Waterway. Ship bunkering would typically occur twice per week, for a period of 4 hours each, or a total of 8 hours per week.

Marine vessels would be bunkered with LNG for fuel using a dedicated marine bunkering arm equipped with a piggyback vapor return line. The arm is hydraulically maneuvered and includes swivel joints that would be swept with nitrogen to prevent ingress of moisture that could freeze and impede arm movement. When connected to the receiving vessel, the LNG bunkering arm and connected piping would be purged with nitrogen, which would be routed to the enclosed ground flare. Once purged, LNG would be bunkered onto the receiving vessel at a maximum design rate of 2,640 gallons per minute. Once bunkering is complete, the liquid in the bunkering arm and in the adjacent piping would be drained back to the LNG storage tank. After draining, the arm and connected piping would be purged with nitrogen again. The nitrogen purge would be routed to the enclosed ground flare and the are/piping depressurized prior to disconnection.

The LNG bunkering arm would be stored under a nitrogen atmosphere. The bunkering arm has the capability to return vapor from the receiving vessel to the LNG storage tank and/or to the enclosed ground flare. However, the LNG fuel tanks on the ships are designed to operate at 100 pounds per square inch (psi). LNG stored on the ship is subcooled and acts to collapse vapor pressure in the ship tanks during fueling (reducing the pressure); hence the vapor return system would not normally be used during bunkering.

LNG may also be supplied to bunker vessels for subsequent transfer to ships. In this process, the bunker vessel would load LNG via the Marine Vessel LNG Fueling System. The bunker vessel would then transit to the LNG-fueled marine vessel, anchor alongside the vessel, and conduct a ship-to-ship transfer of the LNG. This is the process typically used for fuel oil. Because the baseline condition involves bunker barge operations for fuel oil, no additional GHG emissions are modeled for LNG bunker barge operations beyond methane emissions associated with the ship-to-ship transfer process.

GHG emissions associated with bunkering operations are based on a 2015 study for the US

Department of Transportation Maritime Administration.[4] Table 6 summarizes the methane loss rates taken from the study. Note that a small portion of LNG production may be transferred to on-road LNG tanker trucks and then bunkered directly into vessels from the LNG tanker trucks. Emissions from this process are assumed to be similar to a Ship-to-Ship transfer where no vapor recovery system is employed. Methane emissions from the truck loading process described in Section 1.3.4.2.2 are already accounted for in the total PSE facility emissions, hence, only the emissions associated with the bunkering operation are accounted for here.

Table 6. Methane Loss Rates from Bunkering Processes

Process	Vapor Displaced	Boil Off Rate (%/day)	Storage Duration (days)	Recovery Rate	Loss per Bunkering Event
Bunker Barge Loading	0.22%	-	-	95%	0.011%
Bunker Vessel Storage	-	0.15%	4	0%	0.60%
Ship-to-Ship Transfer	0.22%	-	-	0%	0.22%

1.3.4.2.2 Truck Loading

Two loading bays on the west side of the Tacoma LNG Facility would have the capacity to load LNG to 10,000-gallon capacity tanker trucks. The loading bays would be designed to fill a tanker truck at a rate of 300 gallons per minute. Truck loading can be functionally undertaken concurrently with liquefaction, marine loading, or sending out to the pipeline.

Each truck bay would have a liquid supply and vapor return hose. The hoses would be 3 inches in diameter and 20 feet long and made from corrugated braided stainless steel with connections suited for LNG trailers. After truck loading, the liquid hose would be drained to a common, closed truck station sump connected to the Tacoma LNG Facility vapor handling system where it would be allowed to boil off and be re-liquefied or sent to the pipeline. Nitrogen would be used to purge the hoses and facilitate liquid draining and would then be routed to the enclosed ground flare.

1.3.4.3 Enclosed Ground Flare

The enclosed ground flare would be a 35.6 MMBtu per hour heat input capacity air-assisted flare designed for smokeless operation while maintaining a controlled stack temperature and retention time for achieving a 99 percent destruction efficiency of total hydrocarbons and entrained VOCs. The enclosed ground flare would consist of the following four burners:

[4] Corbett J, et al. "Methane Emissions from Natural Gas Bunkering Operations in the Marine Sector: A Total Fuel Cycle Approach." 2015. Available at https://www.marad.dot.gov/wp-content/uploads/pdf/Methane-emissions-from-LNG-bunkering-20151124-final.pdf

- 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 per hour,
- A small standard burner will be used during warm, low flow inlet gas cases that occur rarely during holding mode or facility turndown,
- A large low-NOx burner designed for cold inlet gases will be used during plant upset conditions,
- A small cryogenic burner will be used to flare loading arm/hose purge gas after ship bunkering or truck loading.

The enclosed ground flare would be used to destroy the following types of waste gas streams:

- Gas chromatograph speed loops
- Flare header sweeps
- Seal vents from one feed gas compressor and one refrigerant compressor
- Acid gases from the pretreatment system
- Heavy hydrocarbon storage flash gas
- Heavy hydrocarbon fuel gas (to be conservative, all fuel gas is assumed to be combusted in the flare instead of used in onsite combustion devices).

1.3.4.4 Fugitives from Equipment Leaks

Fugitive methane emissions can occur from leaks in valves, pump seals, flanges, connectors, and compressor seals. There are multiple fugitive minimization features inherent in the Tacoma LNG Facility design. For example, all of the proposed pumps, with the exception of the hydrocarbon liquid pump, will be submerged inside enclosed liquid storage tanks and would have no fugitive leaks to the atmosphere. In addition, leaks from the feed gas compressor seals would also be captured and vented to the enclosed ground flare. However, the BOG would have fugitive methane emissions. In addition, there are several valves, relief valves, and flanged connectors for conveyance of various process fluids that have the potential for fugitive methane leaks. LNG bunkering of ships at the TOTE terminal would not produce any fugitive emissions. However, there are four swivel joints that have seals with the potential to leak methane. We assume that the leak rate of the swivel joints would be similar to that of the pump seals. Component counts by fluid service are provided in Table 7 below.

Table 7: Inventory of Fugitive Equipment Leak Components

Component	Acid gas	BOG	Ethylene	Fuel Gas	HC Liquid	Liquefied NG	Mixed Refrigerant	NG	Untreated NG
Valves	39	9	12	36	33	244	112	185	30
Pressure Relief Valves	3	--	1	3	1	19	8	9	2
Flanges/ Connectors	--	7	2	15	6	114	28	77	15
Pump Seals	--	--	--		1	--	--	--	--
Compressor Seals	--	2	--	--	--	--	1	1	--
Swivel Joints						4			

HC = hydrocarbon
NG = natural gas

PSE would commit as a condition of the Agency Notice of Construction Approval Order to a Leak Detection And Repair (LDAR) program to reduce emissions from equipment leaks. The EPA has found that this type of program achieves emission reductions of 88 percent for light liquid service such as LNG.

1.3.4.5 Emergency Generator

A 1,500 kW ultra-low sulfur diesel-fired emergency generator will be used for back-up power to maintain critical systems in the event of power loss. Under normal operating conditions this generator would only be used once per month for up to 2 hours for readiness testing. Emissions have been conservatively estimated based on 500 hours per year of operation, but this greatly overstates anticipated levels of operation.

1.3.4.6 Natural Gas Pretreatment, Conversion & Storage Greenhouse Gas Emissions

Table 8 below summarizes each component of the Tacoma LNG Facility and compares the GHG emissions stated in the FEIS to the GHG emissions inherent to the final design.

Table 8: Greenhouse Gas Emissions Comparison - FEIS to SEIS

	2015 FEIS (Final)	SEIS (May 2018)
Flare		
Configuration	1 enclosed ground flare & 1 open flare	1 enclosed ground flare
Operating Hours	8,760	8,760
Waste Gas Flow (scf per hour)	33,000	40,417
Waste Gas Heat Input (MMBtu per hour)	10.2	35.6
Total CO2e from Flare (metric tons)	**14,835**	**28,131**
Vaporizer		
Fuel	Natural Gas	Natural Gas
Operating Hours	1,000	240
Heat Content of fuel (btu/scf)	926	1,093
Heater Capacity (MMBtu per hour)	28.5	66.0
Total CO2e from Vaporizer (metric tons)	**981**	**842**
Fugitive GHGs		
Total CO2e from Fugitives (metric tons)	**369**	**95**
Pretreatment Heater (for Dehydrator Regeneration & Amine Reboiler)		
Fuel	Natural Gas	Natural Gas
Operating Hours	8,760	8,760
Heater Capacity (MMBtu per hour)	8.5	10.6
Total CO2e from Pretreatment Heater (metric tons)	**3,952**	**4,930**
Diesel Backup Generator		
Fuel	Distillate #2	Distillate #2
Operating Hours	500	500
Capacity (kW)	1,600	1,500
Total CO2e from Diesel Generator (metric tons)	**614**	**536**
Totals	**2015 FEIS (Final)**	**SEIS (May 2018)**
Total (metric tons)	**20,751**	**34,533**

1.3.4.7 Tacoma LNG Facility Improvements since FEIS

Certain changes have been made to the Tacoma LNG Facility design since the FEIS was issued. All of these changes are insignificant and/or result in lesser impacts. Primary differences that could potentially affect GHG emissions are explained below. Table 8 above identifies the differences that the changes make in GHG emissions.

1.3.4.7.1 LNG Production

The FEIS estimated a production rate of approximately 250,000 to 500,000 gallons of LNG per day. Production in the NOC permit application is capped at an average of 250,000 gallons of LNG per day.

1.3.4.7.2 Vaporizer

The vaporizer in the FEIS was estimated to run 1,000 hours per year utilizing a heater with a 28.5 MMBtu per hour capacity. The vaporizer heater capacity in the final design is 66 MMBtu per hour. Runtime in the air permit application has been capped to 240 hours per year. These changes resulted in a reduction in GHG emissions of approximately 140 metric tons per year from this process as compared to the FEIS.

1.3.4.7.3 Seal Gas Recovery System

A Seal Gas Recovery System (SGRS) to capture leaks from the refrigerant compressor system is included in the final design and in the air permit application. The FEIS did not include a SGRS. The addition of a SGRS results in a 74% reduction in fugitive GHG emissions (approximately 275 metric tons per year) as compared to the FEIS.

1.3.4.7.4 Emergency Generator

The FEIS anticipated installation of a 2,000 kW ultra-low sulfur diesel-fired emergency generator to be used for back-up power to maintain critical systems in the event of power loss. PSE has determined that a 1,500 kW ultra-low sulfur diesel-fired emergency generator will be suitable for back-up power needs.

1.3.4.7.5 Enclosed Ground Flare System

The flare system proposed in the FEIS consisted of one enclosed ground flare burner to be used under all normal operating scenarios. An open flare was also proposed in the FEIS for use in emergency and upset situations only if the system needed to be rapidly evacuated. The open flare would have produced a visible flame, but only during emergency and upset situations.

There were significant upgrades in the final design of the flare for the NOC permit application. First, the open flare was eliminated. Second, the final design of the enclosed ground flare was changed from a 1-burner to a 4-burner configuration to address the wide flow, heat input, and inlet temperature variation experienced by the facility and to minimize NOx emissions. The new configuration would have the potential to handle higher waste gas flow. These improvements to the flare system resulted in an increase in GHG emissions of approximately 13,500 metric tons per year CO_2e from this process as compared to the FEIS.

1.3.4.7.6 Hylebos Waterway

Although not impacting the facility emissions, PSE will not construct the new concrete barge pier in the Hylebos Waterway.

1.3.5 Tacoma LNG Facility Energy Consumption

In addition to the direct facility emissions described in Section 1.3.3 and 1.3.4, upstream GHG emissions are attributable to the electricity consumed by the facility. The proposed Tacoma LNG Facility will consume an estimated 123,455,000 kWh per year of electricity supplied by Tacoma Power.

For calendar year 2016, Tacoma Power reported their mix of generating sources by fuel type as summarized in Table 9.[5]

Table 9. Tacoma Power Generating Mix (2016)

Fuel Type	Percentage Used
Hydro Power	84%
Nuclear*	6%
Coal*	2%
Natural Gas	1%
Wind	7%

*Represents a portion of the power Tacoma Power gets from the Bonneville Power Administration.

GHG emissions associated with the Tacoma Power power grid mix were calculated using GREET 2017. The resulting emissions factors are summarized in Table 10.

Table 10. Upstream GHG Emissions Associated With Facility Electrical Energy Use

Upstream Emissions from Tacoma Power Supply		VOC	CO	NOx	BC	OC	CH_4	N_2O	CO_2
Emissions Rate	grams/MMBTUe	0.649	1.631	3.833	0.023	0.050	10.917	0.092	5,942
Emissions Rate	g/MMBTU LNG	0.040	0.101	0.237	0.001	0.003	0.674	0.006	367.1

The Tacoma LNG Facility also has a "loss factor" associated with the production of LNG relative to the pipeline natural gas supply. It is estimated that the Tacoma LNG Facility will consume 24,756 MMBTU of pipeline natural gas to produce 23,252 MMBTU of LNG. This results in a loss factor of 6.47% and is primarily attributable to the removal of heavy hydrocarbons during the liquefaction process, as described in Section 1.3.3.2.

1.3.6 LNG Consumption

Natural gas has been identified as a key resource to implement criteria pollutant, toxic air pollutant and greenhouse gas emission reductions for the marine transportation industry. The Tacoma LNG Facility would address this need as the marine transportation industry seeks to

[5] Tacoma Power, 2016 Source Report. Available at: https://www.mytpu.org/tacomapower/about-tacoma-power/dams-power-sources/

comply with updated emissions policies (e.g., MARPOL Regulation 14.4) and reduce operational costs. LNG produced by the Tacoma LNG Facility will be used in one of three ways: TOTE vessel fuel, other vessel/vehicle fuel and peak shaving.

1.3.6.1 TOTE Marine Vessel Fuel

In addition to peak-shaving, a primary purpose of the Tacoma LNG Facility would be to supply the TOTE Marine Vessel LNG Fueling System. LNG would be transported by cryogenic pipeline from the Tacoma LNG Facility to the TOTE site where vessels would be fueled using an in-water trestle and loading platform in the Blair Waterway designed to fuel vessels. TOTE would combust the LNG in lieu of burning fuel oil in order to comply with MARPOL Regulation 14.4. The North American Emission Control Area (ECA) being implemented under MARPOL regulations will dramatically reduce air pollution from ships. For marine vessels to be compliant with MARPOL regulations they will have either of two options available:

- Continue to use current engines in their current configuration utilizing compliant 0.1% sulfur fuel within the ECA or 0.5% sulfur fuel in the open ocean (from Jan 1st 2020).
- Retrofit exhaust scrubbers to the vessel and continue to burn HFO.

The U.S. Environmental Protection Agency has documented highly significant public health benefits from implementing the North American ECA including reducing nearly 14,000 premature deaths and relieving respiratory symptoms for nearly five million people each year in the U.S. and Canada.[6]

An emissions model was developed to estimate emissions from short-sea vessels based on assumed operating parameters. The model relies primarily on emissions factors and methodologies employed in the Puget Sound Maritime Air Emissions Inventory (Emissions Inventory), developed by the Puget Sound Maritime Air Forum.[7] This forum is a collaboration of local, state, and federal regulatory agencies, ports, terminal operators, environmental advocacy groups, and others.

Because the Emissions Inventory does not contain emissions factors for LNG-fueled vessels, two recent reports on emissions from LNG-fueled marine engines were used to develop the needed emissions factors.

- NOx, CO, hydrocarbon, methane, and CO2 emissions are taken from a 2017 report by maritime consulting firm SINTEF Ocean AS (formerly MARINTEK).[8] This study

[6] See, https://nepis.epa.gov/Exe/ZyPDF.cgi/P100AU0I.PDF?Dockey=P100AU0I.PDF

[7] Puget Sound Maritime Emissions Inventory, 2016. Available at: https://pugetsoundmaritimeairforum.org/2016-puget-sound-maritime-air-emissions-inventory/

[8] Stenersen D, Thonstad O, “GHG and NOx emissions from gas fuelled engines” 2017. Report # OC2017 F-108; https://www.nho.no/siteassets/nhos-filer-og-bilder/filer-og-

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includes both manufacturer reported emissions data and data from an in-field emissions measurement program.
- VOC emissions are calculated from the ratio of non-methane VOC (NMVOC) to CH4 emissions reported in a 2015 report to MARAD.[9]

It is important to note that dual-fuel LNG engines rely on a small amount of fuel oil injected to act as a "pilot" to initiate combustion in the engine cylinder. This pilot fuel is typically injected at rates of approximately 1-5% of the total fuel rate, with the balance 95-99% of the fuel being natural gas. The pilot fuel contributes to the emissions of the vessel and these contributions are reflected in the emissions factors reported in the studies referenced above.

Table 11 summarizes the assumed route details for the TOTE vessel. These route details are based on direct travel from the origin to Tacoma. Table 12 summarizes the assumed vessel particulars, as reported by IHS Sea-web for TOTE's vessel, Midnight Sun.

Table 11. Route Assumptions for TOTE Vessel Emissions Modeling

Ship Type	Origin	Distance at Sea	Transit Speed	Transit Time	Maneu -vering Time	Time at Berth (Origin)	Time at Berth (Destination)	Transit	Maneu -vering	Hoteling
		(nm)	(knots)	(hours)	(hours)	(hours)	(hours)	(within 200 nm)		
RoRo	Anchorage	1450	22	65.9	2	10	10	14%	50%	50%

Table 12. Vessel Particulars for TOTE's Midnight Sun

Ship Type	Service Speed	Max Speed	Installed Power	Main Engine Speed	Aux Engine Speed	Main Engine Type	Aux Engine Type
	(knots)	(knots)	(kW)	(RPM)	(RPM)		
RoRo	24	25.5	52200	400	720	Medium speed	Medium speed

Based on the above described modeling, the emissions rates for TOTE vessels projected to utilize the proposed PSE facility for LNG bunkering are summarized in Table 13. The emissions rates are based on a one-way trip to/from Anchorage, AK. Because the TOTE vessels currently use shore power to eliminate engine idling while at dock in Tacoma, the estimated emissions rates assume no engine operation during time at berth in Tacoma.

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dokumenter/nox-fondet/dette-er-nox-fondet/presentasjoner-og-rapporter/methane-slip-from-gas-engines-mainreport-1492296.pdf

[9] Corbett J, et al, "Methane Emissions from Natural Gas Bunkering Operations in the Marine Sector: A Total Fuel Cycle Approach", 2015. https://www.marad.dot.gov/wp-content/uploads/pdf/Methane-emissions-from-LNG-bunkering-20151124-final.pdf

Table 13. Estimated Emissions for TOTE Vessel using LNG (per one-way trip)

Pollutant	VOC	CO	NOx	BC	OC	CH_4	N_2O	CO_2
Total Emissions (tons)	0.00	4.75	4.73	0.01	0.02	13.14	0.08	1,103
Emissions Rate (g/kWh)	0.00	1.91	1.91	0.00	0.01	5.29	0.03	444
Emissions Rate (g/MMBTU HFOe HHV)	0.1	244.5	243.7	0.5	1.2	676.5	4.0	56,801
Emissions Rate (g/MMBTU LNG LHV)	0.1	261.5	260.7	0.6	1.2	723.6	4.2	60,750

For purposes of comparison to a baseline No Project condition, emissions rates were also estimated for the TOTE vessel continuing to operate on marine fuel oil with a 0.1% sulfur content. These emissions rates are summarized in Table 14.

Table 14. Estimated Emissions for TOTE Vessel using 0.1% Sulfur Fuel Oil (per one-way trip)

Pollutant	VOC	CO	NOx	BC	OC	CH_4	N_2O	CO_2
Total Emissions (tons)	1.26	2.75	30.40	0.41	0.09	0.02	0.07	1,697
Emissions Rate (g/kWh)	0.51	1.11	12.25	0.17	0.04	0.01	0.03	683
Emissions Rate (g/MMBTU HFOe HHV)	65.0	141.6	1,565.5	21.2	4.7	1.3	3.7	87,363
Emissions Rate (g/MMBTU LSMDO LHV)	69.6	151.4	1,674.3	22.6	5.0	1.4	4.0	93,437

1.3.6.2 Other Marine Vessel Fuel

The remainder of the LNG not used for peak shaving and not provided to TOTE will be sold for other fuel uses. As increasingly stringent marine vessel emissions standards come into effect, it is necessary that the Northwest Seaport Alliance (alliance of Port of Tacoma and Port of Seattle) and other regional ports be able to provide LNG to visiting vessels. Substitution of higher emitting fuel oil with low-emitting LNG results in substantial decreases in emissions of many pollutants including sulfur dioxide, fine particulate, diesel particulate matter and GHGs. Truck loading capacity would be part of the Project to enable movement of LNG to other fueling sites. Other fuel transfer alternatives would be considered in the future as the market is identified. At that time, should modifications to the Tacoma LNG Facility be necessary, all appropriate environmental review and permitting processes would be conducted. It is assumed that all fuel not used by TOTE, on-road heavy duty trucks or for peak shaving would be combusted in marine vessels. Emissions rates for other marine vessels are assumed to be equivalent to emissions rates for TOTE vessels, as described in Section 1.3.6.1. This assumption is conservative as newly built engines are anticipated to have emission rates equal to or less than those of the retrofitted TOTE engines.

Well-to-tank emissions for marine fuel oil are based on default values in GREET 2017 for ultralow sulfur diesel (ULSD) fuel. This pathway was selected because vessels operating within 200 nm of the U.S. coast are currently required to use fuel oil with 0.1% sulfur content or less, rather than traditional heavy fuel oil. GREET 2017 does not have an explicit pathway for marine distillate fuel oils, however, this low sulfur distillate is substantially similar to ULSD fuel oil in that it is a lighter, more highly refined product than traditional heavy fuel oil. Well-to-tank emissions for the ULSD pathway, and utilized here for 0.1% sulfur fuel oil, are summarized in Table 15.

Table 15. Well-to-Tank Emissions for 0.1% Sulfur Fuel Oil

Pollutant	VOC	CO	NOx	BC	OC	CH_4	N_2O	CO_2
Emissions (grams/MMBTU)	8.105	14.18	31.50	0.2917	0.5294	170.2	0.2534	14,222

1.3.6.3 Peak Shaving

The Tacoma LNG Facility would address a long-term need for new peak-day resources as identified through PSE's 2015 biennial integrated resource plan. The Tacoma LNG Facility was evaluated against long-haul interstate pipeline capacity, regional underground natural gas storage service combined with interstate pipeline storage redelivery service, and a stand-alone LNG peaking facility in other locations. PSE determined that the most cost-effective way of meeting its resource needs would be the combination of the Tacoma LNG Facility, and refurbishment of an existing, on-system, peak-day resource. The Tacoma LNG Facility would be projected to enable PSE to meet its customers' natural gas needs without an expansion of the existing gas transmission system (from well fields in northern British Columbia to the Tacoma area), that would otherwise be needed, for at least 10 years.

The Tacoma LNG Facility would also enable PSE to avoid repurposing firm gas transmission from peak period electricity generation to residential gas service. In the absence of the Tacoma LNG Facility, during peak periods PSE would have to use this firm gas transmission to supply gas customers and thus would be required to operate "peaker" dual-fuel combustion turbine electric generating units utilizing fuel oil rather than using natural gas. The additional GHG emissions attributable to use of fuel oil in dual-fuel combustion turbine electric generating units is not quantified in this analysis, but will occur if the Project is not built.

Because the natural gas delivered for peak shaving under the proposed project would be provided by pipeline in the No Project Alternative, the only incremental GHG emissions attributable to peak shaving would exclusively be the facility-level emissions associated with operation of the Tacoma LNG Facility.

1.3.6.4 Gig Harbor LNG Supply

Gig Harbor currently receives LNG supplies by tanker truck from Fortis BC in Delta, British Columbia. LNG is transported by tanker truck approximately 175 miles from the Fortis BC facility to Gig Harbor. Each tanker truck carries approximately 10,000 gallons of LNG. LNG sourced from the Tacoma LNG Facility would be transported in the same manner, but only over a distance of 17 miles between the Tacoma LNG Facility and Gig Harbor.

For purposes of this analysis, it is assumed that the Fortis BC liquefaction facility has similar GHG emissions rates as the proposed facility. Natural gas for both facilities is sourced from British Columbia and received from the Sumas hub. Consequently, the primary differentiators between the No Project condition and the Project condition are the differences in pipeline transport of the natural gas to the liquefaction facilities and the tanker truck transport distance of the LNG.

Table 16. GHG Emissions Rates for Gig Harbor LNG Supply

Pathway Component	Baseline	Proposed Project	Units
NG Extraction, Processing, and Transmission to Sumas	8,193	8,193	gCO2e/MMBTU
Transmission to PSE System	0	810	gCO2e/MMBTU
BC System Distribution	67	0	gCO2e/MMBTU
PSE System Distribution	0	480	gCO2e/MMBTU
Liquefaction	5,397	5,397	gCO2e/MMBTU

Table 17. LNG Tanker Transportation Assumptions for Gig Harbor LNG Supply

LNG Tanker Transport Assumptions	Baseline	Proposed Project	Units
Transport Distance (one-way)	175	17	Miles
Energy Consumption	17,738	17,738	BTU/mile
Well-to-Wheels GHG Emissions Rate	98,088	98,088	gCO2e/MMBTU
Tanker Capacity	10,000	10,000	Gallons
Tanker Capacity	848.2	848.2	MMBTU

1.3.6.5 On-Road Truck Fuel

A small portion of the annual LNG production at the facility may be supplied for use in on-road heavy-duty trucks. GREET 2017 default values for emissions from LNG distribution and storage (Plant-to-Tank) and from LNG combination tractor operation are used to account for downstream emissions after the proposed Tacoma LNG Facility. For purposes of comparison to a baseline No Project condition, Well-to-Wheels emissions rates were also estimated for a diesel-fueled combination tractor. The resulting emissions rates are summarized in Table 18.
These emissions rates are provided on a g/MMBTU of fuel delivered to the vehicle. Based on GREET 2017 default assumptions, the natural gas combination tractor has a 10% efficiency penalty relative to the diesel tractor, meaning that the natural gas tractor will consume 10% more energy per mile of operation than the diesel tractor.

Table 18. Emissions Rates for On-Road Combination Tractors

Pathway Component	VOC	CO	NOx	BC	OC	CH_4	N_2O	CO_2
Plant-to-Tank LNG Combination Tractor (g/MMBTU)	0.308	1.289	7.299	0.019	0.087	104.5	0.017	753
Tank-to-Wheels LNG Combination Tractor (g/MMBTU)	21.07	1,167	66.09	0.358	0.587	248.9	0.026	58,975
Well-to-Wheels Diesel Combination Tractor (g/MMBTU)	31.52	94.58	228.4	0.689	1.182	189.7	0.370	93,234

2.0 APPLICABLE REGULATORY STRUCTURE

2.1 Regulatory Structures that Limit GHG Emissions

The Tacoma LNG Project would be subject to a variety of regulations to ensure that its air emissions do not result in significant negative impacts. These regulations were summarized and assessed in the FEIS. Given the narrow scope of the SEIS, only GHG regulatory structures are addressed below.

The Tacoma LNG Project would be subject to state and federal GHG reporting rules. The state rules are codified in WAC Chapter 173-441 and the federal rules are codified in 40 C.F.R. § 98. Emissions of GHGs are estimated on a carbon dioxide equivalent basis (CO_2e). Estimates of individual GHGs are converted to CO_2e by multiplying each pollutant by its Global Warming Potential (GWP) relative to CO_2. Thus, consistent with WAC 173-441-040, Table A-1 and 40 CFR §98, Table A-1, CO_2 has a GWP of 1, methane (CH_4) has a GWP of 25, and nitrous oxide (N_2O) has a GWP of 298.

2.2 Canadian Regulatory Structures

As noted above, all natural gas used in the Tacoma LNG Project will be sourced from British Columbia and transported from British Columbia by way of the Westcoast Pipeline and the Huntingdon/Sumas export/import point. Therefore, the relevant regulatory structures for the extraction, processing and initial phase of transmission are those of British Columbia and the Canadian national government.

The British Columbia provincial government has adopted a comprehensive set of drilling and production regulations.[10] These regulations are credited with reducing emission intensity by 37 percent per unit of production since 2000.[11] British Columbia further committed to a target of reducing fugitive and vented methane emissions from oil and gas production by 45 percent by 2025 from extraction and processing infrastructure built before January 1, 2015 (estimated at an annual reduction of 1 million tonnes annually in 2025).[12] The British Columbia regulations include standards regarding blowout prevention, cemented well casings, establishment and maintenance of hydraulic isolation for wells, provisions to maintain and inspect the integrity of inactive wells, provisions for plugging and restoring abandoned well sites and filing abandonment reports.

[10] http://www.bclaws.ca/civix/document/id/complete/statreg/282_2010#section17 .

[11] British Columbia's Climate Leadership Program (August 2016); https://climate.gov.bc.ca/app/uploads/sites/13/2016/10/4030_CLP_Booklet_web.pdf

[12] *Id*.

The Canadian national government adopted in April 2018 new regulations that apply to oil and gas facilities responsible for the extraction, production and processing, and transportation of natural gas, including pipelines.[13] The Canadian government's expectation is that the new regulations will result in a 40 to 45 percent reduction from 2012 levels by 2025. The first federal requirements come into force on January 1, 2020, with the rest of the requirements coming into force on January 1, 2023. The requirements target five key methane sources:

- **Fugitive equipment leaks**: Starting January 1, 2020, covered upstream oil and gas facilities must implement Leak Detection And Repair (LDAR) programs. Regular inspections required three times per year and corrective action required if leaks are discovered.
- **Well completions by hydraulic fracturing**: Starting January 1, 2020, covered entities must conserve or destroy gas instead of venting. The Canadian national government noted that British Columbia already has existing provincial measures that cover these activities.
- **Compressors**: Starting January 1, 2020, covered entities must either conserve or destroy methane or else meet applicable limits on methane emissions. Compliance with the venting limits must be measured using a continuous monitoring device.
- **Facility production venting**: Starting January 1, 2023, covered upstream oil and gas facilities must limit vented volumes of methane to 15,000 m^3 per year. These facilities must capture the gas and either use it onsite, re-inject it underground, send it to a sales pipeline, or route it to a flare.
- **Pneumatic devices**: Starting January 1, 2023, a) covered natural gas powered controllers must not operate using hydrocarbon gas, other than propane, unless either (i) the bleed rate is maintained below 0.17 m^3 per hour or (ii) the emissions are conserved or routed to destruction equipment; and b) covered pumps are prohibited from using hydrocarbon gas where liquid pumping exceeds 20 liters per day of methanol unless emissions are conserved or routed to destruction equipment.

British Columbia is required to adopt and implement the federal requirements unless it can demonstrate that its alternative regulations would result in equivalent or better methane reductions.

The life cycle analysis presented in this document takes into account only those British Columbia regulations currently in effect and does not consider the additional benefits that will result from the implementation of the national regulations recently adopted by the Canadian government. Project GHG emissions would be even lower than projected in this document based on the 2018 national regulations.

[13] See, generally, https://www.canada.ca/en/environment-climate-change/news/2018/04/federal-methane-regulations-for-the-upstream-oil-and-gas-sector.html; See specifically, http://laws-lois.justice.gc.ca/PDF/SOR-2018-66.pdf.

3.0 POTENTIAL IMPACTS

3.1 Emissions Calculations from Each Phase Including Project

Net GHG emissions impacts from the proposed Tacoma LNG Facility are dependent on the assumed end uses of the produced LNG. To evaluate a reasonable range of emissions impacts, two scenarios were developed for end use of the LNG. These scenario definitions are summarized in Table 19. Scenario A assumes that all LNG is directed to on-site peak shaving and marine LNG bunkering supply at the Tacoma LNG Facility. Scenario B assumes a more diverse mix of end uses and assesses the utilization of the LNG tanker truck loading racks to supply LNG to Gig Harbor, on-road truck LNG fuel stations, and truck-to-ship bunkering.

Table 19. LNG End Use Scenarios Evaluated

Production End Uses (LNG gallons/year)	Scenario A	Scenario B
Total Production	**91,250,000**	**91,250,000**
On-site Peak Shaving	10,000,000	10,000,000
Gig Harbor Peak Shaving	0	1,825,000
On-road Trucking	0	3,650,000
TOTE Marine	39,000,000	39,000,000
Truck-to-Ship Bunkering	0	1,825,000
Other Marine (by Bunker Barge)	40,425,000	34,950,000

Table 20 and Table 21 summarize the results of the GHG emissions analysis for each scenario, using the emissions factors described in Section 1 of this report. Loss factors, where given, represent the amount of natural gas lost through the associated pathway process. This lost gas increases the upstream gas supply required. Note that loss factors in sequential processes have a compounding effect and cannot be summed to calculate an aggregate loss factor for a combination of processes.

Table 20. Total GHG Emissions Impacts for Scenario A

Scenario A	Project			No Project		
	Fuel Throughput (MMBTU/year)	Loss Factor	GHG Emissions (MT CO2e/year)	Fuel Throughput (MMBTU/year)	Loss Factor	GHG Emissions (MT CO2e/year)
Extraction, processing, and transmission to Sumas hub	**7,269,653**	**0.00%**	**59,563**	**748,262**	**0.00%**	**6,131**
Transmission from Sumas Hub to PSE gate	**7,266,233**	**0.05%**	**5,888**	**747,910**	**0.05%**	**606**
Distribution via PSE System	**7,259,336**	**0.095%**	**3,483**	**747,200**	**0.095%**	**359**
Liquefaction	**6,818,200**	**6.47%**	**36,800**	**0**		**0**
Direct Facility Emissions (includes Peak Shaving)	*6,818,200*		*34,483*	*0*		*0*
Electricity Supply	*6,818,200*		*2,317*	*0*		*0*
Vessel Loading of LNG	**6,071,000**		**14,497**	**0**		**0**
TOTE	*2,914,080*	0.011%	174	*0*		*0*
Bunker Barge	*3,156,920*	0.837%	14,323	*0*		*0*
Truck-to-Vessel	*0*	0.220%	0	*0*		*0*
On-road Heavy-duty Truck Fuel	**0**		**0**	**0**		**0**
LNG (Plant-to-Tank Emissions)	*0*	*0.47%*	*0*	*0*		*0*
LNG (Tank-to-Wheels Emissions)	*0*		*0*	*0*		*0*
ULSD (Well-to-Wheels Emissions)	*0*		*0*	*0*		*0*
Gig Harbor LNG Supply	**0**		**0**	**0**		**0**
Distribution (PSE or BC)	*0*		*0*	*0*	*0.010%*	*0*
Liquefaction	*0*		*0*	*0*	*6.47%*	*0*
LNG (Plant-to-Gig Harbor Emissions)	*0*		*0*	*0*		*0*
TOTE Vessel Operations	**3,001,172**		**235,355**	**6,002,344**		**340,146**
TOTE LNG (Direct Vessel Emissions)	*2,913,759*		*233,733*	*0*		*0*
TOTE Pilot Fuel Oil (Well-to-Tank Emissions)	*87,413*		*1,622*	*0*		*0*
TOTE Fuel Oil (Well-to-Tank Emissions)	*0*		*0*	*3,001,172*		*55,680*
TOTE Fuel Oil (Direct Vessel Emissions)	*0*		*0*	*3,001,172*		*284,466*
Other Vessel Operations	**3,224,427**		**252,863**	**3,224,427**		**365,449**
Other LNG (Direct Vessel Emissions)	*3,130,511*		*251,121*	*0*		*0*
Other Pilot Fuel Oil (Well-to-Tank Emissions)	*93,915*		*1,742*	*0*		*0*
Other Fuel Oil (Well-to-Tank Emissions)	*0*		*0*	*3,224,427*		*59,822*
Other Fuel Oil (Direct Vessel Emissions)	*0*		*0*	*3,224,427*		*305,627*
Total			**608,449**			**712,690**

Table 21. Total GHG Emissions Impacts for Scenario B

Scenario B	Project			No Project		
	Fuel Throughput (MMBTU/year)	Loss Factor	GHG Emissions (MT CO2e/year)	Fuel Throughput (MMBTU/year)	Loss Factor	GHG Emissions (MT CO2e/year)
Extraction, processing, and transmission to Sumas hub	**7,269,653**	**0.00%**	**59,563**	**1,175,291**	**0.00%**	**9,630**
Transmission from Sumas Hub to PSE gate	**7,266,233**	**0.05%**	**5,888**	**1,029,605**	**0.05%**	**834**
Distribution via PSE System	**7,259,336**	**0.095%**	**3,483**	**883,564**	**0.095%**	**424**
Liquefaction	**6,818,200**	**6.47%**	**36,800**	**0**		**0**
Direct Facility Emissions (includes Peak Shaving)	*6,818,200*		*34,483*	*0*		*0*
Electricity Supply	*6,818,200*		*2,317*	*0*		*0*
Vessel Loading of LNG	**5,680,341**		**12,207**	**0**		**0**
TOTE	*2,914,080*	0.011%	174	*0*		*0*
Bunker Barge	*2,611,464*	0.837%	11,848	*0*		*0*
Truck-to-Vessel	*154,797*	0.220%	185	*0*		*0*
On-road Heavy-duty Truck Fuel	**272,728**		**18,703**	**246,769**		**24,205**
LNG (Plant-to-Tank Emissions)	*271,446*	*0.47%*	*915*	*0*		*0*
LNG (Tank-to-Wheels Emissions)	*271,446*		*17,700*	*0*		*0*
ULSD (Well-to-Wheels Emissions)	*0*		*0*	*246,769*		*24,205*
Gig Harbor LNG Supply	**136,364**		**10**	**145,202**		**844**
Distribution (PSE or BC)	*Included above*		*Included above*	*145,187*	*0.010%*	*10*
Liquefaction	*Included above*		*Included above*	*136,364*	*6.47%*	*736*
LNG (Plant-to-Gig Harbor Emissions)	*136,364*		*10*	*136,364*		*98*
TOTE Vessel Operations	**3,001,172**		**235,355**	**6,002,344**		**340,146**
TOTE LNG (Direct Vessel Emissions)	*2,913,759*		*233,733*	*0*		*0*
TOTE Pilot Fuel Oil (Well-to-Tank Emissions)	*87,413*		*1,622*	*0*		*0*
TOTE Fuel Oil (Well-to-Tank Emissions)	*0*		*0*	*3,001,172*		*55,680*
TOTE Fuel Oil (Direct Vessel Emissions)	*0*		*0*	*3,001,172*		*284,466*
Other Vessel Operations	**2,667,307**		**209,173**	**2,667,307**		**302,306**
Other LNG (Direct Vessel Emissions)	*2,589,618*		*207,732*	*0*		*0*
Other Pilot Fuel Oil (Well-to-Tank Emissions)	*77,689*		*1,441*	*0*		*0*
Other Fuel Oil (Well-to-Tank Emissions)	*0*		*0*	*2,667,307*		*49,486*
Other Fuel Oil (Direct Vessel Emissions)	*0*		*0*	*2,667,307*		*252,821*
Total			**581,182**			**678,388**

4.0 IMPACTS OF NO ACTION

Under the No Action Alternative, the Proposed Action would not be implemented. If the Proposed Action is not implemented, a 14% to 15% reduction in GHG emissions will not be realized; the Proposed Action will result in a 14% to 15% reduction in GHGs as compared to the No Action Alternative. The quantitative and qualitative negative impacts associated with the No Action Alternative, as compared to the Proposed Action, are explained below.

Under the No Action Alternative, LNG would not be produced or stored at the Tacoma LNG Facility site for peak shaving use and additional supplies of natural gas and transmission would have to be developed to meet peak demand. In order to address this need, additional wellhead production and accelerated expansion of the existing natural gas transmission pipeline system would be required from the British Columbia wells to Tacoma to provide enough firm gas transmission during times of design peak demand. Thus the No Action Alternative would eliminate the ability to store gas during periods of low demand and require expansion of the natural gas production and transmission infrastructure to ensure adequate supplies during design peak demand. These impacts are not quantified in this assessment but would result in significant GHG emissions.

Under the No Action Alternative, LNG would not be available to displace fuel oil as a regional transportation fuel (marine and on-road). Fuel oil used as marine and on-road transportation fuel has higher life cycle GHG emissions than LNG. Thus, the No Action Alternative would result in continued use of fuel oil and lose the GHG reductions associated with the expanded use of LNG as marine and on-road transportation fuel. Moreover, a new supply of transportation fuel with fewer toxic and criteria pollutant air emissions than traditional fuels would not be available to help improve air quality in the Puget Sound airshed.

Under the No Action Alternative, existing dual-fuel electric generating units utilized during periods of peak demand (i.e., peakers) would be required to be run on fuel oil, rather than natural gas, in order to meet electricity demand during periods of peak natural gas demand. While the additional GHG emissions attributable to operation of the dual-fuel generating units on fuel oil are not quantitatively assessed in this document, an increase in GHG emissions (as well as toxic and criteria pollutant air emissions) would result from this aspect of the No Action Alternative.

Under the No Action Alternative, the economic and employment impacts of the Proposed Action would not be realized.

In short, under the No Action Alternative, significant GHG reductions would not be realized. GHG emissions associated with the Proposed Action are dependent on the mix of end uses of the produced LNG, but are conservatively estimated to be 14% lower under Scenario B and 15% lower under Scenario A than the No Action Alternative. Further details related to the loss of peak shaving and the loss of low emission transportation fuel if the No Action Alternative occurs are presented below.

4.1 Impact of Loss of Peak Shaving Ability

A key aspect of the Tacoma LNG Facility is that it would provide the ability to take natural gas from the transmission pipeline at times when gas is in low demand and thus readily available and store it for use to serve local gas utility customers at times when there is not enough gas available to meet needs (i.e., peak demand). PSE is under a statutory obligation to meet the needs of its firm core residential, commercial and industrial customers. Peak natural gas demand in the region is projected to exceed the amount that the pipeline can supply during design peak periods starting in the winter of 2020/2021. Absent the Project, during such periods, available natural gas allotted for dual-fuel electric generating plants would be redirected to natural gas customers and the generating plants would have to operate on fuel oil. Even with this reallocation of natural gas, if the Project is not built then by 2023 there would not be enough natural gas available to the PSE distribution system to meet gas demand on peak days. Absent the Project, the entire natural gas supply chain, including additional wells and processing equipment and the transmission pipeline system from northern British Columbia wells to Tacoma would have to be expanded to accommodate future system growth.

The Tacoma LNG Facility provides the ability to store gas locally during times of low demand and have it available during times of high area demand, thus decreasing or postponing by many years, the need to expand British Columbia natural gas production and northern British Columbia to Tacoma transmission infrastructure. If the plant is not available, PSE would immediately begin contractual negotiations for expansion of natural gas transmission infrastructure to ensure adequate transmission capacity at times of peak demand.

The No Action Alternative would initially increase GHG emissions from the use of fuel oil to fire dual-fuel electric generating units, and beginning in approximately 2023 would increase GHG emissions from the construction of additional natural gas production and transmission infrastructure. This would include additional natural gas wells, as well as, compressors, processing systems and transmission pipeline that would also result in increased GHG emissions. Although this was not factored into the analysis, the development of additional natural gas production and transmission infrastructure would generate significant additional GHG emissions.

4.2 Impact of Loss of Low Emission Fuel Availability

Besides providing natural gas storage capacity in a constrained area, the Tacoma LNG Facility would also make a low emission fuel source available for marine transportation in the region. The No Action Alternative would result in LNG not being available for use as a low-emission fuel for TOTE vessels as well as other vessels seeking to substitute LNG for higher emitting fuels. In that circumstance, TOTE and other maritime users would either operate on low sulfur fuel oil, or would operate on high sulfur fuel oil and employ energy intensive controls such as seawater scrubbers, to meet the MARPOL emissions limitations. This would mean continued reliance on crude oil and the accompanying refining of the crude oil to fuel oil. As natural gas extraction, processing and marine use (as LNG) have lower GHG emissions than those associated with extracting, refining and combusting marine fuel oil, the No Action Alternative would maintain significantly higher GHG emission rates regionally in addition to losing the significant decrease in criteria and toxic air pollutants associated with the Project.

5.0 CUMULATIVE IMPACTS

The Washington State Environmental Policy Act (SEPA) requires that agencies evaluate cumulative impacts, which include impacts resulting from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions in the action area. In the context of the LNG Project, cumulative impacts are identified on the basis of proposed and reasonably foreseeable significant future developments. At the time that the FEIS was issued, two other projects were identified as major developments that could contribute to the cumulative impacts, the Puyallup Tribal Terminal Project and the Northwest Innovation Works Tacoma methanol manufacturing facility. Both of these projects were subsequently terminated. Since that time, no new projects have been identified as major developments that could contribute to the cumulative impacts.

Targa Sound Terminal (Targa) recently obtained authority from the Agency to repurpose four of its existing storage tanks to hold natural gasoline. In the NOC Work Sheet the Agency stated that the natural gasoline being handled is not expected to contain methane and that "Greenhouse Gas emissions did not increase with this project." Therefore, there does not appear to be a reasonably foreseeable cumulative impact related to Targa.

Even if cumulative impacts attributable to other projects did exist, because the proposed Tacoma LNG Facility results in a net decrease in GHG emissions of at least 14 percent as compared to the No Action Alternative, the Action Alternative is preferable from a cumulative impacts assessment perspective.

6.0 AVOIDANCE, MINIMIZATION AND MITIGATION

Mitigation would only be appropriate to the extent that changes from the proposal previously assessed in the FEIS are identified and so long as there is an applicable SEPA policy adopted by the Agency, the impacts are documented in the applicable environmental document and the measures are reasonable and capable of being accomplished. See, WAC 197-11-660.
The Proposed Action will reduce GHG emissions by at least 14 percent as compared to the No Action Alternative. As the No Action Alternative has greater impacts than the Proposed Action, no mitigation is necessary or appropriate under SEPA.

7.0 CONCLUSIONS

The proposed Tacoma LNG Project would transport natural gas from British Columbia, Canada to Tacoma, Washington, liquefy that gas and make it available for marine fuel, on-road fuel and peak shaving. The Project will enable substantial decreases in air emissions attributable to marine vessels and heavy duty trucks, minimize operation of dual-fuel peak electric generating units on oil and increase available pipeline capacity during peak periods through peak shaving (so delay the need for more natural gas production and transmission infrastructure). The life cycle analysis performed by PSE indicates that the proposed Tacoma LNG Project will also result in at least a 14 percent net reduction in GHG emissions as compared to the No Action Alternative. For all of these reasons, the Proposed Action should be identified as the preferred alternative.

ATTACHMENT A

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May 2, 2018

Subject: Peer Review of "Tacoma Liquefied Natural Gas Project: Supplemental Environmental Impact Statement Background Information Document"

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1 Introduction

This document serves as formal peer review of materials provided to Energy and Environmental Research Associates (EERA) by Thomas R. Wood, of Stoel Rives, LLP regarding the upstream and downstream greenhouse gas (GHG) impacts of an LNG facility being developed in Tacoma, Washington, titled "Tacoma Liquefied Natural Gas Project: Supplemental Environmental Impact Statement Background Information Document" and contained in the file "2018 03-30 PSE SEIS Background Information Document.pdf" (SEIS). The SEIS Background Information Document (BID) was written by Gladstein Neandross Associates (GNA). EERA staff performing the peer review include Dr. James Corbett, Dr. James Winebrake, and Dr. Edward Carr. This peer review was conducted in accordance with academic journal peer review standards and reported to Thomas R. Wood.

This review continues in three parts. We present an overview of our general findings, we identify specific issues within the GNA report, and we summarize general conclusions.

2 Overview

Puget Sound Energy (PSE) is proposing to construct, operate, and decommission a Liquefied Natural Gas (LNG) facility at Tacoma, Washington. The facility is designed to produce an average of 250,000 gallons of LNG per day. The gas supply for the project would come exclusively from British Columbia by way of the Westcoast Pipeline, the Huntingdon/Sumas export/import point, and via pipeline to enter the Tacoma LNG system at Frederickson, approximately 145 miles from the Huntingdon/Sumas export/import point via the Northwest Pipeline. GHG emission rates associated with natural gas transmission via pipeline are based on default fugitive emission rates in the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET[1]) model.

After treatment, heavy hydrocarbon removal, and liquefaction the LNG will be stored in an 8 million gallon low-pressure LNG storage tank at < 3 psig, and maintained below -260°F. One of the primary functions of the LNG facility will be to provide marine bunkering fuel to the Totem Ocean Trailer Express (TOTE) Marine Vessel Fueling System via cryogenic pipeline. TOTE are converting

[1] https://greet.es.anl.gov

two vessels, which travel exclusively between Tacoma and Anchorage on regular schedule to dual fuel engines, capable of burning both LNG and conventional 0.1% marine diesel oil. In addition to vessel bunkering the facility will also provide for truck loading of LNG, supply of LNG to Gig Harbor via truck, and peak shaving.

At present LNG tanker trucks delivering LNG to Gig Harbor travel approximately 175 miles from FortisBC in Delta, British Columbia. The facility would significantly reduce the travel distance of LNG trucks supplying Gig Harbor to approximately 17 miles. The proposed LNG facility would also provide peak shaving services by enabling storage of natural gas in liquid form during periods of low demand and regasifying that fuel for introduction into the existing distribution system during periods of peak demand. The LNG facility would also enable PSE to avoid repurposing firm gas transmission from peak period electricity generation to residential gas service. In the absence of the Tacoma LNG Facility, during peak periods PSE would have to use this firm gas transmission to supply gas customers and thus would be required to operate "peaker" dual-fuel combustion turbine electric generating units utilizing fuel oil rather than natural gas.

3 Review

3.1 Scenarios

The scenarios are clearly defined as "Project" and "No project."

Two LNG scenarios are modeled. Scenario A assumes that all LNG is directed to on-site peak shaving and marine LNG bunkering at the Tacoma LNG facility. Scenario B assumes a wider range of end uses, including the utilization of an LNG tanker truck to supply LNG to Gig Harbor, on-road LNG fuel stations, and truck-to-ship bunkering. The upstream and production stages are identical in the two scenarios, with downstream emissions modeled to be reduced from the no-project conditions by 27,464 MT CO_2e per year in Scenario B.

3.2 Upstream Emissions

3.2.1 Natural Gas Extraction

Gas is extracted in British Columbia (BC) and GNA use a BC study on GHG emissions from gas extraction and processing for this analysis. The analysts point out that the LCA takes "into account only those BC regulations currently in effect and does not consider the additional benefits that would result from the adoption of the national regulations proposed by the Canadian government." The analysts use data from the Canadian government (Table 1 and Table 2) to calculate emissions factors (Table 3). <u>We deem this approach and data reasonable for this analysis</u>.

3.2.2 Natural Gas Transportation Pipelines

Gas is transported to the PSE system via the Westcoast Pipeline and Huntingdon/Sumas (H/S) export/import point and is then further transported via Northwest Pipeline to Frederickson Meter Station. The analysts assume a conservative distance of 145 miles for all gas transmission between H/S and the PSE system. The analysts use GREET 2017 fugitive emissions for pipeline transport (Table 4), which they argue is conservative since these values represent US averages (and the average age of the US pipeline system is older than the Pacific Northwest system – although no evidence is provided to justify this statement). <u>Additional details could be provided by the analysts to justify this claim, and/or demonstrate that alternate numbers would not affect the comparison results</u>.

Gas is transported within the PSE system to near-facility with a lost and unaccounted for gas estimate of 0.095% (19.19 gCH4/MMBtu throughput) (Section 1.3.2). We agree that this is a reasonable value to use for this analysis.

Gas is transported into the facility through underground pipeline and filtered, pressure-boosted, and treated via an Amine Pretreatment System. This process also releases some GHGs. Gas is also cleaned of heavy hydrocarbons and then liquefied. We deem the description to be well-represented in the document.

3.2.3 Vessel Bunkering

LNG is delivered from storage into the natural gas system (vaporization) or from storage to the TOTE vessels (via cryogenic pipeline to TOTE Fueling System or via truck). For the vaporization process, the analysts assumed "all combustible waste gases generated on site are sent to the enclosed ground flare and all process equipment fuel demand is met using natural gas from the pipeline." We deem this to be a reasonable approach for LCA calculations.

For marine bunkering, the analysts assume that the LNG cryogenic pipeline would travel 1,200 feet from the storage facility to a loading arm on a bunkering platform in the Blair Waterway. Bunkering would occur 2x per week, taking approximately four hours; this suggests fewer than 500 hours annually engaged in pipeline marine bunkering operations. We deem these assumptions to be reasonable.

Marine bunkering is also possible in a ship-to-ship configuration. This is also discussed in the report. The analysts only include methane emissions from the ship-to-ship transfer process. The loss per bunkering event is 0.22%, or approximately 840 gallons per bunkering event. We deem this appropriate.

The analysts use a recent US DOT study (Corbett, et al., 2015) as emissions factors and leakage effects for the bunkering operations. We deem these values as appropriate.

3.3 Downstream Emissions

Downstream uses vary by scenario, with scenario A representing an upper bound, and scenario B producing fewer estimated emissions, mainly because of non-marine diversions associated with lower estimated releases.

3.3.1 LNG Vessel Emission Estimation

Original Comment: April 18, 2018

We note the following discrepancies between the GNA BID and "2018 04-05 Copy of TOTE Vessel Emissions Model" spreadsheets:

- An estimate of 12.87 tons per trip (cell AL20) appears on worksheet "TOTE – LNG," when methane (CH_4) slip is entered as 5.3g/kWh in cell S16 on worksheet "Emissions Factors."
- This number does not agree with estimated emissions of 13.14 tons per trip, shown in cell Q31 on sheet "LNG Vessel Emissions" in the "2018 04-05 LCA calculations for SEIS," which is the same as the value for per-trip CH_4 emissions shown in Table 11 of the SEIS Background Information Document.

- Adjustments for methane slip of 6.9g/kWh in cell S16 on worksheet "Emissions Factors," in the "2018 04-05 Copy of TOTE Vessel Emissions Model" workbook (16.76 tons per trip) are also not in agreement with the estimates shown in cell Q44 on sheet "LNG Vessel Emissions" in the "2018 04-05 LCA calculations for SEIS" workbook.

Because the emissions values in the "2018 04-05 LCA calculations for SEIS" workbook are hard-coded it is not possible to determine the exact origin of the 13.14 tons per tip CH_4 estimate. Similar discrepancies exist for CO_2 between the "2018 04-05 Copy of TOTE Vessel Emissions Model" workbook and the BID in Table 13. These inconsistencies can be resolved. We recommend that the analyst correct errors between the spreadsheets and the BID.

Update: May 2, 2018
Upon review of a corrected spreadsheet, we determine that the above issues have been addressed and that the analysis is consistent and well-calculated. There are no new discrepancies among the spreadsheets and the BID.

3.3.2 Methane Slip Assumptions

The BID assumes methane slip of 5.3g/kWh under the base case, which is the average value from on-board testing of two ships with low pressure dual fuel (LPDF) engines. This value is taken from Table 7.1.2 of the SINTEF report[2], reported in g/kWh.

We evaluated how these values might affect the SEIS estimated of annual methane releases, and how that would compare with other accepted studies (IMO GHG3 report). Using 13.14 short tons of CH_4 emissions per trip, and a total of 186 TOTE Alaska scheduled one-way trips per year, the BID yields an estimate of 2,217,082 kgCH_4/year from methane slip.

The third IMO Greenhous Gas Report[3] estimates methane slip at 0.0512 g/g fuel (Table 34). While engine efficiency plays an important role in conversions between fuel usage and emissions, assuming no efficiency losses and 1,612 grams/gal, and total LNG fuel throughput of 39,000,000 gal/year consumed, we estimate 62,868 metric tons of fuel consumed. Thus, using the IMO methane slip rate gives an estimate of 3,218,842 kgCH_4/year from methane slip, which is 45.2% larger than the SEIS methane slip estimate.

Our review of Table 7.2 in the SINTEF report shows manufacturer testbed estimates of 7.6 gCH_4/kWh. The ratio of the testbed estimate to the SINTEF CH_4 estimates in Table 7.2 of the SINTEF report (7.6/5.3 = 1.434) is approximately equal to the difference in total methane slip emissions estimated using the IMO methane slip estimate (1.452). As noted, methane slip estimates are uncertain due to a lack of observed operational data. We suggest adding this 7.6 gCH_4/kWh value as a high estimate of the potential emissions from methane slip. This change would adopt the upper estimates from the SINTEF report that align with established best practices from the IMO report.

[2] Stenersen and Thonstad (2017) GHG and NOx emissions from gas fueled engines. SINTEF Ocean AS. 2017-06-13. https://www.nho.no/siteassets/nhos-filer-og-bilder/filer-og-dokumenter/nox-fondet/dette-er-nox-fondet/presentasjoner-og-rapporter/methane-slip-from-gas-engines-mainreport-1492296.pdf

[3] Third IMO GHG Study 2014; International Maritime Organization (IMO) London, UK, April 2015; Smith, T. W. P.; Jalkanen, J. P.; Anderson, B. A.; Corbett, J. J. et al.

As discussed in the SINTEF report in section 4.4.1.2 the conversion of the MAN engines aims to optimize the engine for gas operation, as shown by the injector change to optimized versions for the smaller volume of pilot diesel fuel used. Additionally, the minimized dead space or crevices in the combustion chamber contribute to reduced methane slip levels. In this scenario the SINTEF report proposes that CH_4 slip can be as low as 3.0 to 4.0 g/kWh. Based on the changes to the MAN engines, and without the luxury of real test data at this time, the BID documents reviewed claim that TOTE methane slip rates of 5.3 gCH_4/kWh would be conservative.

<u>We find the claim of conservativeness to rely upon an expectation that the TOTE vessel engines will have similar 3-4 gCH_4/kWh methane slip rates, similar to "best performance" values in the SINTEF report.</u>

3.3.3 Thermal Efficiency

We understand that various ratios available in the Miller Cycle may increase thermal efficiency but reduce engine power. We need more information on the Miller Cycle operations for TOTE engines to make judgments that the Miller Cycle adjustments will not degrade vessel power output to the point actual voyage conditions may not match operating times and engine loads estimated in the spreadsheets. <u>This issue merits increased attention as it affects the vessel duty cycle and power assumptions.</u>

3.4 Fugitive Emissions

The analysts conduct an inventory of fugitive equipment leak components (Table 7) to address possible natural gas leaks. <u>We deem this to be a reasonable list of components affecting routine leakage rates</u>.

3.5 Differences Between FEIS and Current Project

The analysts compare the FEIS with the project before PSCAA for air permitting and characterize the main differences in these EIS reports. <u>We deem the explanations provided as appropriate and reasonable</u>.

3.6 GHG Emissions from Electric Utilities

The analysts use GREET 2017 to determine the GHG emissions from electric utilities (Table 10) based on the electricity generation mix found in Table 9. <u>We deem these to be appropriate emissions rates</u>.

4 Conclusion

We assess whether reviewed data and modeling calculations represent current best practices, whether estimates of GHG emissions result in appropriate findings and conclusions and identify key inputs, assumptions, or conditions that, if reasonably modified, could affect the main conclusions.

We find that data and modeling calculations generally represent current best practices, and that model estimates are interpreted accurately, leading to appropriate conclusions based on model inputs. We find that emissions estimates associated with natural gas extraction, natural gas transportation, vessel bunkering, fugitive emissions, and GHG emissions from electric utilities are appropriate.

In general we find the emissions estimation methodology to be appropriate, but identified several shortcomings that may be worth addressing.

We document a number of errors between the spreadsheets provided and the final report related to CH_4 and CO_2 estimates, which should be corrected. These errors were corrected, re-reviewed, and found to be consistent across documents.

We find that inputs for methane slip remain highly uncertain. Some claims of "conservative" inputs can be challenged and should be adjusted upward to conform with current best practices.

Further work may be necessary to confirm new-engine methane slip rates, and to confirm that power and thermal efficiency performance in engines using the Miller Cycle will be as modeled and/or per engine manufacturer commitments.

ATTACHMENT B

PUGET SOUND ENERGY RESPONSE TO COMMENTS IN ENERGY & ENVIRONMENTAL RESEARCH ASSOCIATES PEER REVIEW DOCUMENT (MAY 2, 2018)

Energy & Environmental Research Associates, LLC (EERA) prepared a peer review of the *Tacoma Liquefied Natural Gas Project, Supplemental Environmental Impact Statement Background Information Document* (EERA Peer Review) at the request of Puget Sound Energy, Inc. (PSE). EERA was selected to serve this valuable function as a result of their international reputation for assessing greenhouse gas life cycle emissions, particularly in relation to maritime projects. The May 2, 2018 EERA Peer Review presents a series of comments about how the Background Information Document (BID) was prepared. These begin in Section 3.2 of the EERA Peer Review and were underlined by the authors for ease of reference. Each comment from the EERA Peer Review is reproduced in its entirety below in italics and PSE's response provided immediately afterwards to each conclusion.

Section 3.2.1 Natural Gas Extraction

Gas is extracted in British Columbia (BC) and GNA use a BC study on GHG emissions from gas extraction and processing for this analysis. The analysts point out that the LCA takes "into account only those BC regulations currently in effect and does not consider the additional benefits that would result from the adoption of the national regulations proposed by the Canadian government." The analysts use data from the Canadian government (Table 1 and Table 2) to calculate emissions factors (Table 3). We deem this approach and data reasonable for this analysis.

> **PSE Response**: PSE appreciates the efforts of EERA to validate the emissions estimates underlying the BID.

Section 3.2.2 Natural Gas Transportation Pipelines
Gas is transported to the PSE system via the Westcoast Pipeline and Huntingdon/Sumas (H/S) export/import point and is then further transported via Northwest Pipeline to Frederickson Meter Station. The analysts assume a conservative distance of 145 miles for all gas transmission between H/S and the PSE system. The analysts use GREET 2017 fugitive emissions for pipeline transport (Table 4), which they argue is conservative since these values represent US averages (and the average age of the US pipeline system is older than the Pacific Northwest system – although no evidence is provided to justify this statement). Additional details could be provided by the analysts to justify this claim, and/or demonstrate that alternate numbers would not affect the comparison results.

> **PSE Response**: PSE appreciates this comment and has revised Section 1.3.2 of the BID to provide justification for the claim that the relevant pipeline segment is significantly newer than the national average.

Gas is transported within the PSE system to near-facility with a lost and unaccounted for gas estimate of 0.095% (19.19 gCH4/MMBtu throughput) (Section 1.3.2). We agree that this is a reasonable value to use for this analysis.

PSE Response: PSE appreciates the efforts of EERA to validate the emissions estimates underlying the BID.

Gas is transported into the facility through underground pipeline and filtered, pressure-boosted, and treated via an Amine Pretreatment System. This process also releases some GHGs. Gas is also cleaned of heavy hydrocarbons and then liquefied. <u>We deem the description to be well-represented in the document.</u>

PSE Response: PSE appreciates the efforts of EERA to comment on the process description in the BID.

Section 3.2.3 Vessel Bunkering
LNG is delivered from storage into the natural gas system (vaporization) or from storage to the TOTE vessels (via cryogenic pipeline to TOTE Fueling System or via truck). For the vaporization process, the analysts assumed "all combustible waste gases generated on site are sent to the enclosed ground flare and all process equipment fuel demand is met using natural gas from the pipeline." <u>We deem this to be a reasonable approach for LCA calculations</u>.

PSE Response: PSE appreciates the efforts of EERA to validate the assumptions and approaches underlying the BID.

For marine bunkering, the analysts assume that the LNG cryogenic pipeline would travel 1,200 feet from the storage facility to a loading arm on a bunkering platform in the Blair Waterway. Bunkering would occur 2x per week, taking approximately four hours; this suggests fewer than 500 hours annually engaged in pipeline marine bunkering operations. <u>We deem these assumptions to be reasonable.</u>

PSE Response: PSE appreciates the efforts of EERA to validate the assumptions and approaches underlying the BID.

Marine bunkering is also possible in a ship-to-ship configuration. This is also discussed in the report. The analysts only include methane emissions from the ship-to-ship transfer process. The loss per bunkering event is 0.22%, or approximately 840 gallons per bunkering event. <u>We deem this appropriate.</u>

PSE Response: PSE appreciates the efforts of EERA to validate the emissions estimates underlying the BID.

The analysts use a recent US DOT study (Corbett, et al., 2015) as emissions factors and leakage effects for the bunkering operations. <u>We deem these values as appropriate</u>.

PSE Response: PSE appreciates the efforts of EERA to validate the emissions estimates underlying the BID.

Section 3.3.1 LNG Vessel Emission Estimation
Original Comment: April 18, 2018
We note the following discrepancies between the GNA BID and "2018 04-05 Copy of TOTE Vessel Emissions Model" spreadsheets:

• An estimate of 12.87 tons per trip (cell AL20) appears on worksheet "TOTE – LNG," when methane (CH_4) slip is entered as 5.3g/kWh in cell S16 on worksheet "Emissions Factors."

• This number does not agree with estimated emissions of 13.14 tons per trip, shown in cell Q31 on sheet "LNG Vessel Emissions" in the "2018 04-05 LCA calculations for SEIS,"which is the same as the value for per-trip CH4 emissions shown in Table 11 of the SEIS Background Information Document.

• Adjustments for methane slip of 6.9g/kWh in cell S16 on worksheet "Emissions Factors," in the "2018 04-05 Copy of TOTE Vessel Emissions Model" workbook (16.76 tons per trip) are also not in agreement with the estimates shown in cell Q44 on sheet "LNG Vessel Emissions" in the "2018 04-05 LCA calculations for SEIS" workbook.

Because the emissions values in the "2018 04-05 LCA calculations for SEIS" workbook are hardcoded it is not possible to determine the exact origin of the 13.14 tons per tip CH4 estimate. Similar discrepancies exist for CO2 between the "2018 04-05 Copy of TOTE Vessel Emissions Model" workbook and the BID in Table 13. These inconsistencies can be resolved. <u>We recommend that the analyst correct errors between the spreadsheets and the BID.</u>

Update: May 2, 2018
<u>Upon review of a corrected spreadsheet, we determine that the above issues have been addressed and that the analysis is consistent and well-calculated. There are no new discrepancies among the spreadsheets and the BID.</u>

PSE Response: As noted in the comment, EERA identified several spreadsheet errors that were corrected in the revised version of the BID. PSE appreciates the efforts of EERA to review the work underlying the BID and bring errors to our attention. The final BID has been corrected to address the comments and is a stronger document as a result of EERA's review.

Section 3.3.2 Methane Slip Assumptions
The BID assumes methane slip of 5.3g/kWh under the base case, which is the average value from on-board testing of two ships with low pressure dual fuel (LPDF) engines. This value is taken from Table 7.1.2 of the SINTEF report2, reported in g/kWh.

We evaluated how these values might affect the SEIS estimated of annual methane releases, and how that would compare with other accepted studies (IMO GHG3 report). Using 13.14 short tons of CH4 emissions per trip, and a total of 186 TOTE Alaska scheduled one-way trips per year, <u>the BID yields an estimate of 2,217,082 kgCH4/year from methane slip</u>.

The third IMO Greenhous Gas Report3 estimates methane slip at 0.0512 g/g fuel (Table 34). While engine efficiency plays an important role in conversions between fuel usage and emissions, assuming no efficiency losses and 1,612 grams/gal, and total LNG fuel throughput of 39,000,000 gal/year consumed, we estimate 62,868 metric tons of fuel consumed. Thus, using the IMO methane slip rate gives an estimate of 3,218,842 kgCH4/year from methane slip, which is 45.2% larger than the SEIS methane slip estimate.

Our review of Table 7.2 in the SINTEF report shows manufacturer testbed estimates of 7.6 gCH4/kWh. The ratio of the testbed estimate to the SINTEF CH4 estimates in Table 7.2 of the SINTEF report (7.6/5.3 = 1.434) is approximately equal to the difference in total methane slip emissions estimated using the IMO methane slip estimate (1.452). As noted, methane slip estimates are uncertain due to a lack of observed operational data. We suggest adding this 7.6 gCH4/kWh value as a high estimate of the potential emissions from methane slip. This change would adopt the upper estimates from the SINTEF report that align with established best practices from the IMO report.

As discussed in the SINTEF report in section 4.4.1.2 the conversion of the MAN engines aims to optimize the engine for gas operation, as shown by the injector change to optimized versions for the smaller volume of pilot diesel fuel used. Additionally, the minimized dead space or crevices in the combustion chamber contribute to reduced methane slip levels. In this scenario the SINTEF report proposes that CH4 slip can be as low as 3.0 to 4.0 g/kWh. Based on the changes to the MAN engines, and without the luxury of real test data at this time, the BID documents reviewed claim that TOTE methane slip rates of 5.3 gCH4/kWh would be conservative.

We find the claim of conservativeness to rely upon an expectation that the TOTE vessel engines will have similar 3-4 gCH4/kWh methane slip rates, similar to "best performance" values in the SINTEF report.

> **PSE Response**: PSE does not believe that it would be appropriate to adjust methane emission factors upwards as suggested in this EERA comment. The best available knowledge about emissions from LNG engines is found in the 2017 SINTEF Ocean AS Report (SINTEF Report). EERA is correct that Table 7.2 of the SINTEF Report shows manufacturer testbed estimates of 7.6 gCH_4/kWh. However, we do not agree with EERA's suggestion of "adding this 7.6 gCH_4/kWh value as a high estimate of the potential emissions from methane slip" based on EERA's suggestion that "This change would adopt the upper estimates from the SINTEF report that align with established best practices from the IMO report." None of engines considered in the IMO report referenced by EERA incorporated the best practices/slip improvements that are being planned for the TOTE engine retrofits. The SINTEF Report states that if an engine is retrofitted using a suite of best practices/slip improvements consistent with those being implemented by TOTE, methane slip can be reduced to a level of 3.0 to 4.0 gCH_4/kWh.[1] In choosing to use the 5.3 gCH_4/kWh from the SINTEF Report (which reflects actual measurements from low pressure dual fuel engines not benefitting from the full suite of

[1] SINTEF report, Section 4.4.1.2.

best practices/slip improvements) we were choosing to use the more conservative measured number. This value is not expected to give full credit for the array of methane slip improvements being incorporated as part of the TOTE engine retrofit. Therefore, we stand by the conclusion that the 5.3 gCH_4/kWh emission factor is conservative.

Section 3.3.3 Thermal Efficiency
We understand that various ratios available in the Miller Cycle may increase thermal efficiency but reduce engine power. We need more information on the Miller Cycle operations for TOTE engines to make judgments that the Miller Cycle adjustments will not degrade vessel power output to the point actual voyage conditions may not match operating times and engine loads estimated in the spreadsheets. <u>This issue merits increased attention as it affects the vessel duty cycle and power assumptions.</u>

PSE Response: TOTE operates its engines on an extremely tight schedule that would be incompatible with any changes to the vessel engine performance that result in reduced engine power. PSE has prepared its calculations in reliance on TOTE's extensive work evaluating the engine retrofits and TOTE's ultimate conclusion that there will not be a material loss of engine power as a result of the engine retrofit project.

3.4 Fugitive Emissions
The analysts conduct an inventory of fugitive equipment leak components (Table 7) to address possible natural gas leaks. <u>We deem this to be a reasonable list of components affecting routine leakage rates</u>.

PSE Response: PSE appreciates the efforts of EERA to validate the assumptions and approaches underlying the BID.

3.5 Differences Between FEIS and Current Project
The analysts compare the FEIS with the project before PSCAA for air permitting and characterize the main differences in these EIS reports. <u>We deem the explanations provided as appropriate and reasonable</u>.

PSE Response: PSE appreciates the efforts of EERA to validate the explanations presented in the BID.

3.6 GHG Emissions from Electric Utilities
The analysts use GREET 2017 to determine the GHG emissions from electric utilities (Table 10) based on the electricity generation mix found in Table 9. <u>We deem these to be appropriate emissions rates</u>.

PSE Response: PSE appreciates the efforts of EERA to validate the emissions estimates underlying the BID.

ATTACHMENT C
(SCENARIO A)

Scenario Definitions

Production End Uses (LNG gallons/year)	Scenario A	Scenario B
Total Production	91,250,000	91,250,000
On-site Peak Shaving	10,000,000	10,000,000
Gig Harbor Peak Shaving	0	1,825,000
On-road Trucking	0	3,650,000
TOTE Marine	39,000,000	39,000,000
Truck-to-Ship Bunkering	0	1,825,000
Other Marine (by Bunker Barge)	42,250,000	34,950,000

Scenario A	Project			No Project		
	Fuel Throughput (MMBTU/year)	Loss Factor	GHG Emissions (MT CO2e/year)	Fuel Throughput (MMBTU/year)	Loss Factor	GHG Emissions (MT CO2e/year)
Extraction, processing, and transmission to Sumas hub	**7,269,653**	**0.00%**	**59,563**	**748,262**	**0.00%**	**6,131**
Transmission from Sumas Hub to PSE gate	**7,266,233**	**0.05%**	**5,888**	**747,910**	**0.05%**	**606**
Distribution via PSE System	**7,259,336**	**0.095%**	**3,483**	**747,200**	**0.095%**	**359**
Liquefaction	**6,818,200**	**6.47%**	**36,800**	**0**		**0**
Direct Facility Emissions (includes Peak Shaving)	*6,818,200*		*34,483*	*0*		*0*
Electricity Supply	*6,818,200*		*2,317*	*0*		*0*
Vessel Loading of LNG	**6,071,000**		**14,497**	**0**		**0**
TOTE	*2,914,080*	0.011%	174	*0*		*0*
Bunker Barge	*3,156,920*	0.837%	14,323	*0*		*0*
Truck-to-Vessel	*0*	0.220%	0	*0*		*0*
On-road Heavy-duty Truck Fuel	**0**		**0**	**0**		**0**
LNG (Plant-to-Tank Emissions)	*0*	*0.47%*	*0*	*0*		*0*
LNG (Tank-to-Wheels Emissions)	*0*		*0*	*0*		*0*
ULSD (Well-to-Wheels Emissions)	*0*		*0*	*0*		*0*
Gig Harbor LNG Supply	**0**		**0**	**0**		**0**
Distribution (PSE or BC)	*Included above*		*Included above*	*0*	*0.010%*	*0*
Liquefaction	*Included above*		*Included above*	*0*	*6.47%*	*0*
LNG (Plant-to-Gig Harbor Emissions)	*0*		*0*	*0*		*0*
TOTE Vessel Operations	**3,001,172**		**235,355**	**6,002,344**		**340,146**
TOTE LNG (Direct Vessel Emissions)	*2,913,759*		*233,733*	*0*		*0*
TOTE Pilot Fuel Oil (Well-to-Tank Emissions)	*87,413*		*1,622*	*0*		*0*
TOTE Fuel Oil (Well-to-Tank Emissions)	*0*		*0*	*3,001,172*		*55,680*
TOTE Fuel Oil (Direct Vessel Emissions)	*0*		*0*	*3,001,172*		*284,466*
Other Vessel Operations	**3,224,427**		**252,863**	**3,224,427**		**365,449**
Other LNG (Direct Vessel Emissions)	*3,130,511*		*251,121*	*0*		*0*
Other Pilot Fuel Oil (Well-to-Tank Emissions)	*93,915*		*1,742*	*0*		*0*
Other Fuel Oil (Well-to-Tank Emissions)	*0*		*0*	*3,224,427*		*59,822*
Other Fuel Oil (Direct Vessel Emissions)	*0*		*0*	*3,224,427*		*305,627*
Total			**608,449**			**712,690**

ULSD Well-to-Tank Emissions (GREET 2017 defaults for Scenario Year 2018)

VOC	CO	NOx	PM10	PM2.5	SOx	BC	OC	CH4	N2O	CO2	CO2e
8.105	14.182	31.498	2.162	1.752	16.7	0.292	0.5	170.2	0.3	14,222	18,553

On-road Truck Emissions (GREET 2017 defaults for Scenario Year 2018)

Pathway Component	VOC	CO	NOx	BC	OC	CH_4	N_2O	CO_2	CO_2e	Loss Factor
Plant-to-Tank LNG Combination Tractor (g/MMBTU)	0.308	1.289	7.299	0.019	0.087	104.5	0.017	753.4	3,371	0.47%
Tank-to-Wheels LNG Combination Tractor (g/MMBTU)	21.07	1,167	66.09	0.358	0.587	248.9	0.026	58,975	65,205	0.00%
Well-to-Wheels Diesel Combination Tractor (g/MMBTU)	31.52	94.58	228.4	0.689	1.182	189.7	0.370	93,234	98,088	

Well-to-Wheels Energy Consumption, Water Consumption, and Emissions of Heavy-Duty Vehicles

Based on default GREET 2017 values for Scenario Year 2018

CIDI Combination Long-Haul Trucks: Conventional and LS Diesel

	Btu/mile or Gallon/mile or g/mile				Btu/mmBtu or Gallon/mmBtu or g/mmBtu			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	1,484	2,237	17,738	21,459	83,677	126,119	1,000,000	1,209,796
Fossil Fuels	1,415	2,206	17,738	21,359	79,746	124,380	1,000,000	1,204,126
Coal	184	84	0	268	10,377	4,728	0	15,105
Natural Gas	951	1,459	0	2,410	53,607	82,280	0	135,887
Petroleum	280	663	17,738	18,681	15,762	37,372	1,000,000	1,053,134
Water Consumption	0	0	0	0	18	5	0	23
CO2 (w/ C in VOC & CO)	111	141	1,402	1,654	6,277	7,939	79,019	93,234
CH4	3	0	0	3.365	148.852	21.363	19.517	189.731
N2O	0	0	0	0.007	0.109	0.145	0.116	0.370
GHGs	191	153	1,413	1,756	10,771	8,618	79,635	99,024
VOC: Total	0.071	0.072	0.415	0.559	4.023	4.082	23.413	31.519
CO: Total	0.159	0.093	1.426	1.678	8.953	5.234	80.390	94.578
NOx: Total	0.391	0.168	3.492	4.051	22.042	9.461	196.870	228.373
PM10: Total	0.022	0.017	0.117	0.156	1.227	0.935	6.621	8.783
PM2.5: Total	0.018	0.013	0.057	0.088	1.035	0.717	3.228	4.980
SOx: Total	0.171	0.125	0.010	0.306	9.656	7.044	0.545	17.244
BC Total	0.003	0.002	0.007	0.012	0.194	0.097	0.397	0.689
OC Total	0.007	0.003	0.012	0.021	0.384	0.146	0.653	1.182
VOC: Urban	0.012	0.042	0.179	0.233	0.684	2.357	10.068	13.109
CO: Urban	0.006	0.035	0.613	0.655	0.359	1.980	34.568	36.907
NOx: Urban	0.019	0.057	1.502	1.578	1.078	3.223	84.654	88.955
PM10: Urban	0.001	0.010	0.050	0.062	0.084	0.543	2.847	3.474
PM2.5: Urban	0.001	0.007	0.025	0.033	0.068	0.417	1.388	1.873
SOx: Urban	0.024	0.065	0.004	0.092	1.331	3.641	0.234	5.206
BC: Urban	0.000	0.001	0.003	0.004	0.009	0.052	0.171	0.231
OC: Urban	0.000	0.001	0.005	0.007	0.020	0.066	0.281	0.367

SI Combination Long-Haul Trucks: LNG, NA NG

	Btu/mile or Gallon/mile or g/mile				Btu/mmBtu or Gallon/mmBtu or g/mmBtu			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	1,539	2,495	19,709	23,743	78,086	126,599	1,000,000	1,204,685
Fossil Fuels	1,530	2,479	19,709	23,718	77,623	125,767	1,000,000	1,203,390
Coal	25	45	0	70	1,261	2,266	0	3,527
Natural Gas	1,426	2,297	19,709	23,432	72,353	116,557	1,000,000	1,188,910
Petroleum	79	137	0	216	4,009	6,945	0	10,954
Water Consumption	0	0	0	0	3	1	0	4
CO2 (w/ C in VOC & CO)	101	146	1,162	1,410	5,137	7,412	58,975	71,524
CH4	3	3	5	10.951	163.448	143.277	248.900	555.625
N2O	0	0	0	0.004	0.139	0.045	0.026	0.210
GHGs	199	231	1,310	1,739	10,078	11,722	66,449	88,248
VOC: Total	0.134	0.022	0.415	0.572	6.824	1.110	21.072	29.005
CO: Total	0.273	0.134	23.000	23.407	13.849	6.801	1,166.982	1,187.632
NOx: Total	0.368	0.247	1.303	1.918	18.672	12.544	66.094	97.310
PM10: Total	0.009	0.012	0.117	0.138	0.453	0.600	5.959	7.011
PM2.5: Total	0.008	0.011	0.057	0.076	0.405	0.560	2.905	3.870
SOx: Total	0.224	0.048	0.000	0.272	11.358	2.438	0.000	13.796
BC Total	0.003	0.001	0.007	0.011	0.143	0.044	0.358	0.545
OC Total	0.003	0.007	0.012	0.021	0.137	0.343	0.587	1.068
VOC: Urban	0.000	0.001	0.179	0.180	0.000	0.066	9.061	9.127
CO: Urban	0.000	0.012	9.890	9.902	0.000	0.605	501.802	502.407
NOx: Urban	0.000	0.024	0.560	0.584	0.000	1.226	28.421	29.647
PM10: Urban	0.000	0.001	0.050	0.052	0.000	0.063	2.562	2.625
PM2.5: Urban	0.000	0.001	0.025	0.026	0.000	0.059	1.249	1.308
SOx: Urban	0.000	0.006	0.000	0.006	0.000	0.323	0.000	0.323
BC: Urban	0.000	0.000	0.003	0.003	0.000	0.004	0.154	0.157
OC: Urban	0.000	0.001	0.005	0.006	0.000	0.034	0.253	0.287

3) Calculations of Energy Consumption, Water Consumption, and Emissions for Each Stage

Scenario Year: 2018

Grid Mix for Stationary Use: Tacoma PUD

	LNG Transportation and Distribution: As a Transportation Fuel	LNG Storage: As a Transportation Fuel	Plant-to-Tank Emissions
Energy efficiency			
Urban emission share	67.0%	70.0%	
Loss factor	1.003	1.011	
Share of feedstock input as feed (the remaining input as process fuel)			
Shares of process fuels			
Residual oil			
Diesel fuel			
Gasoline			
Natural gas			
Coal			
N-butane			
Hydrogen			
Electricity			
Feed loss			
Energy use: Btu/mmBtu of fuel throughput (except as noted)			
Residual oil			
Diesel fuel			
Gasoline			
Natural gas: process fuel			
Coal			
Natural gas: feed loss			
Natural gas flared			
N-butane			
Hydrogen			
Electricity			
Feedstock loss	538	4,186	4,724
Total energy	11,029	4,186	15,215
Fossil fuels	10,928	4,186	15,114
Coal	2	0	2
Natural gas	4,525	4,186	8,711
Petroleum	6,401	0	6,401
Water consumption	0.240	0.000	0.240
Total emissions: grams/mmBtu of fuel throughput			
VOC	0.308		0.308
CO	1.289		1.289
NOx	7.299		7.299
PM10	0.162		0.162
PM2.5	0.151		0.151
SOx	0.727		0.727
BC	0.019		0.019
OC	0.087		0.087
CH4: combustion	2.013		2.013
N2O	0.017		0.017
CO2	753		753
CH4: leakage	11.672	90.819	102.491
VOC evaporation			0.000
Misc. Items	58.358	230.256	288.614
Urban emissions: grams/mmBtu of fuel throughput			
VOC	0.042		0.042
CO	0.142		0.142
NOx	0.810		0.810
PM10	0.020		0.020
PM2.5	0.018		0.018
SOx	0.093		0.093
BC	0.002		0.002
OC	0.009		0.009

GREET Emissions Results (GREET 2017)

1. Well-to-Pump Energy Consumption, Water Consmption and Emissions: Btu or Gallon or g per mmBtu of Fuel Available at Fuel Station Pumps

	Baseline Conventional and LS Diesel
Total Energy	209,839
WTP Efficiency	82.7%
Fossil Fuels	204,179
Coal	15,074
Natural Gas	135,897
Petroleum	53,208
Water consumption	23
CO2 (w/ C in VOC & CO)	14,222
CH4	170.187
N2O	0.253
GHGs*	19,395
VOC	8.105
CO	14.182
NOx	31.498
PM10	2.162
PM2.5	1.752
SOx	16.719
BC	0.292
OC	0.529
VOC: Urban	3.041
CO: Urban	2.339
NOx: Urban	4.301
PM10: Urban	0.627
PM2.5: Urban	0.485
SOx: Urban	4.969
BC: Urban	0.060
OC: Urban	0.087

*GHG equivalent values calculated by GREET using AR5/100 GWPs. This value is not used in the model. Instead, CO2e values are calculated using emissions rates of the individual gases and their appropriate GWPs.

Summary (g/MMBTU)	CH4	N2O	CO2	CO2e
BC Production and Processing	45.5	0.16	6,030	7,216
BC Transmission	5.9	0.02	824	978
WA Transmission	13.679	0.295	377.793	810
PSE Distribution	19.2			480
Total				9,484

BC Province

2017 NIR: Table A12-11 (million tonnes CO2e)	2010	2011	2012	2013	2014	2015	Natural Gas Only (million tonnes of gas) CO2 (2015)	CH4 (2015)	N2O (2015)	CO2e(2015)
Natural Gas Production and Processing	10.4	11.7	11.8	12	12	10.9	9.07	0.069	0.0002388	10.9
Oil and Natural Gas Transmission	1.1	1.1	1	1.4	1.2	1.5	1.24	0.009	0.0000322	1.5
Natural Gas Distribution	0.1	0.1	0.1	0.1	0.1	0.1	0.01	0.003	0.0000004	0.1
Total	11.6	12.9	12.9	13.5	13.3	12.5	10.3	0.1	0.0	12.4

BC "Natural Gas Only" values are a subset of Canada's 2017 NIR, provided by Frank Neitzert - Chief, Energy Section - Canada Science and Risk Assessment Directorate

BC Distribution System		
Methane Emissions	3,438,658,571	grams CH4/year
Associated Energy Content	153,646	MMBTU
Loss Factor	0.010%	

BC Gas Production Volumes and Export Volumes (1000 m3)	2010	2011	2012	2013	2014	2015
Residue Gas Plant Outlet - BC Production Only	29,808,782	35,572,183	35,723,237	38,663,739	41,241,670	43,339,421

https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-gas-oil/production-statistics/gasnew.xls

Report does not specific standard or normal cubic meters. Assuming normal cubic meter

Natural Gas Heat Content	983	BTU/SCF
Cubic meters to cubic feet	35.3147	SCF/Nm3

BC Province

BC Natural Gas GHG Emissions (grams/MMBTU)	2010	2011	2012	2013	2014	2015	CO2 (2015)	CH4 (2015)	N2O (2015)	CO2e (2015)
Natural Gas Production and Processing	10,050	9,475	9,515	8,941	8,382	7,245	6,030	45.5	0.16	7,216
Oil and Natural Gas Transmission	1,063	891	806	1,043	838	997	824	5.9	0.02	978
Natural Gas Distribution	97	81	81	75	70	66	10	2.3	0.00	67
Total	11,210	10,446	10,402	10,058	9,290	8,308	6,863	53.7	0.18	8,260
Total Ex-Distribution	11,113	10,366	10,322	9,984	9,220	8,242	6,853	51.5	0.18	8,193

Washington State

Washington State Gas Transmission (g/MMBTU-mile)	VOC	CO	NOx	PM10	PM2.5	SOx	BC	OC	CH4	N2O	CO2
Pipeline Compression/Transport	0.0057	0.0293	0.0348	0.0001	0.0001	0.0005	0.0000	0.0000	0.0288	0.0020	2.6112
Methane Leakage									0.0657		

Transmission Distance 144.68 miles Distance from FERC Form 567. Sumas interconnect to Frederickson Meter Station

Washington State Gas Transmission (g/MMBTU)	VOC	CO	NOx	PM10	PM2.5	SOx	BC	OC	CH4	N2O	CO2	CO2e
Pipeline Compression/Transport	0.826	4.243	5.034	0.015	0.013	0.079	0.002	0.004	4.169	0.295	377.793	572.554
Methane Leakage	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	9.511	0.000	0.000	237.765
Total	0.826	4.243	5.034	0.015	0.013	0.079	0.002	0.004	13.679	0.295	377.793	810.319

Loss Factor

Leakage Rate 0.048% Gas lost through the system

9.511 gCH4/MMBTU
0.0000495 MMBTU/gCH4
0.05%

Washington State

PSE Distribution System Leakage Rate 0.095% Based on natural gas receipts. This includes lost and unaccounted for gas, of which leakage is only a portion.

0.0000495 MMBTU/gCH4
19.19 gCH4/MMBTU
479.8 gCO2e/MMBTU

GREET 2017 - Emissions for NG Transmission to LNG Plant.

Scenario year	2018
Transmission Distance	150 miles
Grid Mix	WECC

Natural Gas as a Feedstock to Produce Transportation Fuels	NG Transmission to LNG Plant (as a final transportation fuel)
Energy efficiency	
Urban emission share	2.0%
Loss factor	1.000
Share of feedstock input as feed (the remaining input as process fuel)	
Shares of process fuels	
Residual oil	
Diesel fuel	
Gasoline	
Natural gas	
Coal	
N-butane	
Hydrogen	
Electricity	
Feed loss	
Energy use: Btu/mmBtu of fuel throughput (except as noted)	
Residual oil	
Diesel fuel	
Gasoline	
Natural gas: process fuel	
Coal	
Natural gas: feed loss	
Natural gas flared	
N-butane	
Hydrogen	
Electricity	
Feedstock loss	478
Total energy	7,322
Fossil fuels	7,261
Coal	108
Natural gas	7,127
Petroleum	27
Water consumption	0.057
Total emissions: grams/mmBtu of fuel throughput	
VOC	0.857
CO	4.399
NOx	5.219
PM10	0.016
PM2.5	0.013
SOx	0.082
BC	0.003
OC	0.004
CH4: combustion	4.322
N2O	0.306
CO2	392
CH4: leakage	9.860
VOC evaporation	
Misc. Items	
Urban emissions: grams/mmBtu of fuel throughput	
VOC	0.115
CO	0.607
NOx	0.721
PM10	0.003
PM2.5	0.002
SOx	0.005
BC	0.000
OC	0.001

Gig Harbor LNG Supply

Baseline - Delivery from Fortis by truck

NG Extraction, Processing, and Transmission to Sumas	8,193	gCO2e/MMBTU
BC Distribution System	67	gCO2e/MMBTU
Liquefaction	5,397	gCO2e/MMBTU
Transport by Tanker Truck	718	gCO2e/MMBTU
Transport Distance	175	miles
Energy Consumption	17,738	BTU/mile
Well-to-Wheels GHG Emissions Rate	98,088	gCO2e/MMBTU
Tanker Capacity	10,000	gallons
Tanker Capacity	848.2	MMBTU
Total Production and Transport	**14,376**	**gCO2e/MMBTU**

Project - Delivery from PSE by truck

NG Extraction, Processing, and Transmission to Sumas	8,193	gCO2e/MMBTU
Transmission to PSE System	810	gCO2e/MMBTU
PSE System Distribution	480	gCO2e/MMBTU
Liquefaction	5,397	gCO2e/MMBTU
Transport by Tanker Truck	70	gCO2e/MMBTU
Transport Distance	17	miles
Energy Consumption	17,738	BTU/mile
Well-to-Wheels GHG Emissions Rate	98,088	gCO2e/MMBTU
Tanker Capacity	10,000	gallons
Tanker Capacity	848.2	MMBTU
Total Production and Transport	**14,951**	**gCO2e/MMBTU**

Summary	gCO2e/MMBTU LNG produced
Direct Emissions	5,058
Electricity (Upstream) Emissions	339.81
Total	5,397

PSE Facility: Direct Emissions

Fuel Production 250,000 gallons per day

Case	Units	VOC	CO	NOx	PM10	PM2.5	SOx	BC	OC	CH4	N2O	CO2	CO2e
May 2018 update to Nov 21 PTE	tons/year	48.81	12.27	3.83		1.27	9.14	0.21	0.54	44.75	0.06	36,829	38,011
May 2018 update to Nov 21 PTE	grams/MMBTU	6.494	1.633	0.510	0.000	0.169	1.216	0.028	0.072	5.955	0.007	4,900	5,058

PSE Facility: Electricity Supply Emissions

Electricity Demand	123,455,000	kWh/year @ 10 million gpy production under PTE
kWh to MMBTU	293	kWh/MMBTU
Electricity Demand	421,246	MMBTUe/year

Facility Emissions from Tacoma PUD Supply		VOC	CO	NOx	PM10	PM2.5	SOx	BC	OC	CH4	N2O	CO2	CO2e
Upstream Electricity Emissions	grams/MMBTUe	0.649	1.631	3.833	0.728	0.314	11.621	0.023	0.050	10.917	0.092	5,942	6,244
Annual Electricity-related Emissions	grams/year	273,551	687,243	1,614,636	306,799	132,470	4,895,272	9,610	20,976	4,598,716	38,661	2,503,064,548	2,630,080,543
Annual Electricity-related Emissions	g/MMBTU LNG	0.040	0.101	0.237	0.045	0.019	0.718	0.0014	0.0031	0.674	0.006	367.12	339.81

PSE Facility: Natural Gas Supply

MMBTU of supply per MMBTU of LNG produced	106%
Loss Factor	6.47%

Production End Uses (LNG gallons/year)	**Scenario A**	**Scenario B**	Scenario A **Current Scenario**
Total Production	91,250,000	91,250,000	91,250,000
On-site Peak Shaving	10,000,000	10,000,000	10,000,000
Gig Harbor Peak Shaving	0	1,825,000	0
On-road Trucking	0	3,650,000	0
TOTE Marine	39,000,000	39,000,000	39,000,000
Truck-to-Ship Bunkering	0	1,825,000	0
Other Marine (by Bunker Barge)	42,250,000	34,950,000	42,250,000

GREET 2017 - Emissions for Delivered Electricity

Scenario year 2018

Grid Mix Tacoma PUD

9) Fuel-Cycle Energy Use, Water Consumption, and Emissions of Electric Generation: Btu or Gallons or Grams per mmBtu of Electricity Available at User Sites (wall outlets)

	Stationary Use: User Defined Mix			
	Total		Urban	
	Feedstock	Fuel	Feedstock	Fuel
Total energy	4,193	1,108,653		
Fossil fuels	3,286	65,872		
Coal	67	44,529		
Natural gas	2,273	21,343		
Petroleum	946	0		
Water consumption	2.276	1,177.196		
VOC	0.564	0.085	0.012	0.029
CO	0.823	0.809	0.042	0.271
NOx	1.480	2.353	0.077	0.850
PM10	0.408	0.320	0.002	0.119
PM2.5	0.080	0.234	0.001	0.087
SOx	0.558	11.063	0.009	4.200
BC	0.009	0.013	0.000	0.005
OC	0.017	0.033	0.001	0.011
CH4	10.846	0.071		
N2O	0.019	0.073		
CO2	221	5,721		
CO2 (w/ C in VOC & (	224	5,723		
GHGs	554	5,744		

LNG Bunkering Emissions

https://www.marad.dot.gov/wp-content/uploads/pdf/Methane-emissions-from-LNG-bunkering-20151124-final.pdf

Summary	**Methane Emissions Rate (gCH4/MMBTU delivered)**	**GHG Emissions Rate (gCO2e/MMBTU delivered)**	**Fraction of Gas Delivered by this Process**
Ship/Barge Loading	2.4	60.16	100%
Bunker Vessel Storage	131.2	3,281	52%
Truck/Ship-to-Ship Transf	47.8	1,196	52%
Total	181.5	2,388	

Loss Factor 0.4403% Gas lost through the system

Net Delivered LNG 380,000 gallons per typical bunkering event

Bunker Barge Loading

Vapor Displaced	Recovery Rate	Loss per Bunkering Event	Volume per Bunkering Event (gallons)	Volume Lost per Bunkering Event (gallons)	Methane Emissions Rate (gCH4/MMBTU)	GHG Emissions Rate (gCO2e/MMBTU)
0.22%	95%	0.011%	383,179	42.1	2.4	60.16

Bunker Vessel Storage

Boil off rate (%/day)	Duration (days)	Recovery Rate	Loss per Bunkering Event	Volume per Bunkering Event (gallons)	Volume Lost per Bunkering Event (gallons)	Methane Emissions Rate (gCH4/MMBTU)	GHG Emissions Rate (gCO2e/MMBTU)
0.15%	4	0%	0.60%	383,137	2,299	131.2	3,281

Ship-to-Ship Transfer

Vapor Displaced	Recovery Rate	Loss per Bunkering Event	Volume per Bunkering Event (gallons)	Volume Lost per Bunkering Event (gallons)	Methane Emissions Rate (gCH4/MMBTU)	GHG Emissions Rate (gCO2e/MMBTU)
0.22%	0%	0.22%	380,838	838	47.8	1,196

End Uses	**Volume (LNG gallons/year)**	**Loss Factor**	**Methane Emissions (LNG Gallons/year)**	**Methane Emissions (gCH4/year)**
TOTE	39,000,000	0.0110%	4,290	6,954,855
Other Bunker Barge	42,250,000	0.8365%	353,434	572,916,195
Truck-to-Ship Bunkering	0	0.2205%	0	0
Total	81,250,000	0.4403%	357,724	579,871,050

Summary	gCO2e/MMBTU
Vessel Operations	75,003

TOTE Vessel Emissions

Estimate from model based on Puget Sound Maritime Emissions Inventory methodology

Ship Emissions and Fuel Consumption Estimates

Inputs

Route Definition

Ship Type	Origin	Destination	Distance at Sea (nm)	Transit Speed (knots)	Transit Time (hours)	Maneuvering Time (hours)	Time at Berth (Origin - hours)	Time at Berth (Destination - hours)	Time within 200 nm: Transit	Time within 200 nm: Manuvering	Time within 200 nm: Hotelling
RoRo	Anchorage	Tacoma	1450	22	65.9	2	10	0	14%	50%	50%

Vessel Details

Service Speed (knots)	Max Speed (knots)	Installed Power (kW)	Main Engine Speed (RPM)	Aux Engine Speed (RPM)	Main Engine Type	Aux Engine Type	Boiler Type
24	25.5	52200	400	720	Low Pressure DF LNG All	Low Pressure DF LNG All	LNG Aux Boiler All

Mode	Time	Main Engine Load (kW)	Aux Engine Load (kW)	Aux Boiler Load (kW)	Fuel - In ECA	Fuel - Outside ECA	Total Emissions (tons per trip): NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4	BC	OC	CO2e
Transit	65.9	33396	514	0	LNG	LNG	4.68	0.00	4.68	0.24	0.05	0.05	0.00	1094	0.08	13.06	0.01	0.02	1,445
Manuvering	2	1044	1541	275	LNG	LNG	0.03	0.00	0.05	0.00	0.00	0.00	0.00	3	0.00	0.03	0.00	0.00	4
Hotelling	10	0	890	275	LNG	LNG	0.03	0.00	0.02	0.00	0.00	0.00	0.00	6	0.00	0.05	0.00	0.00	8
Total Emissions (tons)							4.73	0.00	4.75	0.24	0.05	0.05	0.00	1103	0.08	13.14	0.01	0.02	1,457
Emissions Rate (g/kWh)							1.91	0.00	1.91	0.10	0.02	0.02	0.00	444	0.03	5.29	0.00	0.01	587
Emissions Rate (g/MMBTU HFOe, HHV basis)							243.7	0.1	244.5	12.4	2.7	2.7	0.0	56801	4.0	676.5	0.5	1.2	75,003
Emissions Rate (g/MMBTU LNG, LHV basis)							260.7	0.1	261.5	13.3	2.9	2.9	0.0	60750	4.2	723.6	0.6	1.2	80,217

At 5.3 g/kWh methane slip: NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4
4.68	0.00	4.68	0.24	0.05	0.05	0.00	1094	0.08	13.06
0.03	0.00	0.05	0.00	0.00	0.00	0.00	3	0.00	0.03
0.03	0.00	0.02	0.00	0.00	0.00	0.00	6	0.00	0.05
4.73	0.00	4.75	0.24	0.05	0.05	0.00	1103	0.08	13.14
1.91	0.00	1.91	0.10	0.02	0.02	0.00	444	0.03	5.29
243.7	0.1	244.5	12.4	2.7	2.7	0.0	56801	4.0	676.5

Summary	**gCO2e/MMBTU**
Vessel Operations	88,624

TOTE Vessel Emissions

Estimate from model based on Puget Sound Maritime Emissions Inventory methodology

Ship Emissions and Fuel Consumption Estimates

Inputs

Route Definition

Ship Type	Origin	Destination	Distance at Sea (nm)	Transit Speed (knots)	Transit Time (hours)	Maneuvering Time (hours)	Time at Berth (Origin - hours)	Time at Berth (Destination - hours)	Time within 200 nm: Transit	Time within 200 nm: Manuvering	Time within 200 nm: Hotelling
RoRo	Anchorage	Tacoma	1450	22	65.9	2	10	0	14%	50%	50%

Vessel Details

Service Speed (knots)	Max Speed (knots)	Installed Power (kW)	Main Engine Speed (RPM)	Aux Engine Speed (RPM)	Main Engine Type	Aux Engine Type	Boiler Type
24	25.5	52200	400	720	Medium speed diesel 2000 - 2010	Medium speed diesel 2000 - 2010	Fuel Oil Aux Boiler All

Mode	Time	Main Engine Load (kW)	Aux Engine Load (kW)	Aux Boiler Load (kW)	Fuel - In ECA	Fuel - Outside ECA
Transit	65.9	33396	514	0	MGO (0.1% S)	MGO (0.1% S)
Manuvering	2	1044	1541	275	MGO (0.1% S)	MGO (0.1% S)
Hotelling	10	0	890	275	MGO (0.1% S)	MGO (0.1% S)

Total Emissions (tons per trip)	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4	BC	OC	CO2e
Transit	30.11	1.23	2.71	1.05	0.63	0.50	0.63	1683	0.07	0.02	0.41	0.09	1,707
Manuvering	0.17	0.03	0.03	0.00	0.00	0.00	0.00	4	0.00	0.00	0.00	0.00	5
Hotelling	0.13	0.01	0.01	0.01	0.00	0.00	0.00	10	0.00	0.00	0.00	0.00	10
Total Emissions (tons)	30.40	1.26	2.75	1.06	0.63	0.51	0.63	1697	0.07	0.02	0.41	0.09	1,721
Emissions Rate (g/kWh)	12.25	0.51	1.11	0.43	0.25	0.20	0.25	683	0.03	0.01	0.17	0.04	693
Emissions Rate (g/MMBTU HFOe, HHV basis)	1565.5	65.0	141.6	54.5	32.5	26.0	32.5	87363	3.7	1.3	21.2	4.7	88,624
Emissions Rate (g/MMBTU HFO, LHV basis)	1674.3	69.6	151.4	58.3	34.8	27.8	34.8	93437	4.0	1.4	22.6	5.0	94,785

4) Mass fractions of black carbon and organic carbon emissions of corresponding PM2.5 emission factors

4.1) Stationary, mobile, and open burning emission sources, %

	Natural gas						Coal		Biomass		
	Boiler	Engine	Combined	Simple cy	Nonroad E	Flared	Boiler	IGCC	Industrial,	IGCC	Open burn
BC	16.5	20.0	2.9	2.9	9.8	95.0	4.3	4.3	13.8	13.8	12.1
OC	42.8	42.8	68.0	68.0	83.7	5.0	8.1	8.1	32.6	32.6	33.9

	Diesel								Gasoline		
	Industrial,	Simple cy	Engine	Nonroad v	Nonroad E	Locomotiv	HDDT 8b	HDDT 6	Engine	Off-road v	Nonroad E
BC	10.0	10.0	81.3	56.3	77.1	8.4	16.0	8.1	10.0	13.6	9.8
OC	25.0	25.0	18.1	34.9	21.1	88.6	66.0	88.0	32.0	86.4	83.7

	Residual fuel oil				Crude oil	Biochar	Jet fuel	
	Boiler	Engine	Simple cy	Ocean tan	Boiler	Boiler	Cruise	Landing and take-offs
BC	6.3	15.0	6.0	15.0	2.9	6.2	31.3	35.8
OC	4.4	39.0	4.0	39.0	2.1	79.9	30.3	26.0

Specifications of Fuels, Global Warming Potentials of Greenhouse Gases, and Carbon and Sulfur Ratios of Pollutants

1) Specifications of Fuels

Fuel	Heating Value			Density	C ratio	S ratio	S ratio			
	Calculation: LHV	LHV	HHV		(% by wt)	(ppm by wt)	Actual ratio by wt	LHV/HHV		
Use LHV or HHV in calculations?	1	1 -- LHV; 2 -- HHV								
Liquid Fuels:	**Btu/gal**	**Btu/gal**	**Btu/gal**	**grams/gal**					grams/MMBTU	
Crude oil	129,670	129,670	138,350	3,205	85.3%	16,000	0.016000	0.937		
Synthetic crude oil (SCO)	135,085	135,085	144,476	3,266	85.6%	1,800	0.001800	0.935		
Bitumen	152,371	152,371	162,964	3,840	83.0%	48,000	0.048000	0.935		
Dilbit (After Recovery)	152,371	152,371	162,964	3,840	83.0%	48,000	0.048000	0.935		
Dilbit (Before Recovery)	145,194	145,194	155,288	3,500	83.2%	37,227	0.037227	0.935		
Diluent	128,449	128,449	137,378	2,709	84.1%	1,600	0.001600	0.935		
Shale Oil (Bakken)	125,601	125,601	134,009	3,087	0.853	16000	0.016000	0.937		
Shale Oil (Eagle Ford)	122,493	122,493	130,692	2,984	0.853	16000	0.016000	0.937		
Gasoline blendstock	116,090	116,090	124,340	2,819	86.3%	10	0.000010	0.934		
Gasoline	112,194	112,194	120,439	2,836	82.8%	9	0.000009	0.932		
CA gasoline	112,194	112,194	120,439	2,836	82.8%	9	0.000009	0.932		
High Octane Fuel (E25)	106,150	106,150	114,388	2,861	77.8%	8	0.000008	0.928		
High Octane Fuel (E40)	100,186	100,186	108,416	2,887	72.7%	6	0.000006	0.924		
U.S. conventional diesel	128,450	128,450	137,380	3,167	86.5%	200	0.000200	0.935		
CA diesel	129,488	129,488	138,490	3,206	87.1%	11	0.000011			
Diesel for non-road engines	128,450	128,450	137,380	3,167	86.5%	11	0.000011	0.935		
Low-sulfur diesel	129,488	129,488	138,490	3,206	87.1%	11	0.000011	0.935		
Petroleum naphtha	116,920	116,920	125,080	2,745	85.0%	1	0.000001	0.935		
Low Octane Gasoline-Like Fuel (LOF)	118,237	118,237	126,586	2,834	85.3%	10	0.000010	0.934		
Conventional Jet Fuel	124,307	124,307	132,949	3,036	86.2%	700	0.000700	0.935		
ULS Jet Fuel	123,041	123,041	131,595	2,998	86.0%	11	0.000011	0.935		
NG-based FT naphtha	111,520	111,520	119,740	2,651	84.2%	0	0.000000	0.931		
Residual oil	140,353	140,353	150,110	3,752	86.8%	5,000	0.005000	0.935		
Bunker fuel for ocean tanker	140,353	140,353	150,110	3,752	86.8%	27,000	0.027000	0.935		
Methanol	57,250	57,250	65,200	3,006	37.5%	0	0.000000	0.878		
Ethanol	76,330	76,330	84,530	2,988	52.2%	1	0.000001	0.903		
Butanol	99,837	99,837	108,458	3,065	64.9%	0	0.000000	0.921		
Acetone	83,127	83,127	89,511	2,964	62.0%	0	0.000000	0.929		
E-Diesel Additives	116,090	116,090	124,340	2,819	86.3%	10	0.000010	0.934		
Liquefied petroleum gas (LPG)	84,950	84,950	91,410	1,923	82.0%	0	0.000000	0.929		
Liquefied natural gas (LNG)	74,720	74,720	84,820	1,621	75.0%	0	0.000000	0.881	21694.33 g/MMBTU LHV	6818200
Dimethyl ether (DME)	68,930	68,930	75,610	2,518	52.2%	0	0.000000	0.912		
Dimethoxy methane (DMM)	72,200	72,200	79,197	3,255	47.4%	0	0.000000	0.912		
Methyl ester (biodiesel, BD)	119,550	119,550	127,960	3,361	77.6%	0	0.000000	0.934		
Fischer-Tropsch diesel (FTD)	123,670	123,670	130,030	3,017	85.3%	0	0.000000	0.951		
Renewable Diesel I (SuperCetane)	117,059	117,059	125,294	2,835	87.1%	0	0.000000	0.934		
Renewable Diesel II (UOP-HDO)	122,887	122,887	130,817	2,948	87.1%	0	0.000000	0.939		
Renewable Diesel III (PNNL-HTL)	123,542	123,542	133,070	3,003	87.1%	0	0.000000	0.928		
Renewable Gasoline	115,983	115,983	124,230	2,830	84.0%	0	0.000000	0.934		
Renewable Gasoline (IDL)	111,560	111,560	119,493	2,655	83.4%	10	0.000010	0.934		
SPK (FT Jet Fuel/HRJ)	119,777	119,777	128,103	2,866	84.7%	0	0.000000	0.935		
Liquid hydrogen	30,500	30,500	36,020	268	0.0%	0	0.000000	0.847		
Methyl tertiary butyl ether (MTBE)	93,540	93,540	101,130	2,811	68.1%	0	0.000000	0.925		
Ethyl tertiary butyl ether (ETBE)	96,720	96,720	104,530	2,810	70.6%	0	0.000000	0.925		
Tertiary amyl methyl ether (TAME)	100,480	100,480	108,570	2,913	70.6%	0	0.000000	0.925		
Butane	94,970	94,970	103,220	2,213	82.8%	0	0.000000	0.920		
Isobutane	90,060	90,060	98,560	2,118	82.8%	0	0.000000	0.914		
Isobutylene	95,720	95,720	103,010	2,253	85.7%	0	0.000000	0.929		
Propane	84,250	84,250	91,420	1,920	81.8%	0	0.000000	0.922		
Natural gas liquids	83,686	83,686	90,050	2,532		0	0.000000	0.929		
n-Hexane	105,125	105,125	112,166	2,479	83.6%	0	0.000000	0.937		
Gaseous Fuels (at 32F and 1atm):	**Btu/ft3**	**Btu/ft3**	**Btu/ft3**	**gms/ft3**				**LHV/HHV**		
Natural gas	983	983	1,089	22.0	72.4%	6	0.000006	0.903		
Pure Methane	962	962	1,068	20.3	75.0%	0	0.000000	0.901		
Gaseous hydrogen	290	290	343	2.6	0.0%	0	0.000000	0.845		
Carbon Dioxide				56.0	27.3%	0	0.000000			
Still gas (in refineries)	982	982	1,044	20.3	75.8%	6	0.000006	0.941		
Solid Fuels:	**Btu/ton**	**Btu/ton**	**Btu/ton**					**LHV/HHV**		
Coal Mix for Electricity Generation	19,474,169	19,474,169	20,673,610		58.6%	10,456	0.010456			
Bituminous coal	22,639,320	22,639,320	23,633,493		61.2%	15,352	0.015352	0.958		
Subbituminous coal	16,085,444	16,085,444	17,449,320		53.7%	3,568	0.003568	0.922		
Lignite coal	10,805,183	10,805,183	12,992,302		49.1%	9,064	0.009064	0.832		
Synthetic coal	22,639,320	22,639,320	23,633,493		80.6%	16,143	0.016143	0.958		
Waste coal	9,945,646	9,945,646	11,958,783		32.6%	9,064	0.009064	0.832		
Pet Coke	26,949,429	26,949,429	28,595,925		86.7%	45,138	0.045138	0.942		
Tire Derived Fuel	26,664,354	26,664,354	28,293,434		48.8%	45,138	0.045138	0.942		
Coking coal	24,599,422	24,599,422	25,679,670		74.7%	11,800	0.011800	0.958		
Catalyst Coke	28,385,750	28,385,750	30,120,000		86.4%	45,138	0.045138	0.942		
Willow	15,396,000	15,396,000	16,524,000		48.7%	500	0.000500	0.932		
Poplar	15,929,000	15,929,000	17,062,000		50.1%	200	0.000200	0.934		
Switchgrass	14,447,000	14,447,000	15,583,000		46.6%	1,100	0.001100	0.927		
Miscanthus	15,342,000	15,342,000	16,377,000		47.6%	800	0.000800	0.937		
Corn stover	14,716,000	14,716,000	15,774,000		46.7%	1,000	0.001000	0.933		
Forest residue	17,289,000	17,289,000	17,906,000		50.3%	400	0.000400	0.966		
Clean Pine	15,929,000	15,929,000	17,062,000		50.1%	200	0.000200	0.934		
Yard trimming waste	15,000,000	15,000,000			47.8%	400	0.000400			
Sugarcane straw	13,454,049	13,454,049	15,774,000		50.0%			0.853		
Sugarcane bagasse	12,381,771	12,381,771	14,062,678		46.3%			0.880		
Bio-char	18,916,911	18,916,911	18,916,911		51.2%	0	0.000000	1.000		
Grain sorghum bagasse	12,781,599	12,781,599	14,131,556		39.3%	0	0.000000	0.904		
Sweet sorghum bagasse	14,409,931	14,409,931	15,305,245		42.0%	0	0.000000	0.942		
Forage sorghum bagasse	14,409,931	14,409,931	15,305,245		42.0%	0	0.000000	0.942		
Municipal solid waste (defined by EISA)	11,209,639	11,209,639	13,583,445		49.2%	1,765	0.001765	0.825		
Convertible municipal solid waste	14,155,275	14,155,275	16,144,033		50.5%	1,787	0.001787	0.877		

2) Global Warming Potentials of Greenhouse Gases: relative to CO2

Metrics for Carbon Dioxide, Methane, Nitrous Oxide

AR Edition/Type	AR4/GWP
Time Horizon (YR)	100
CO2	1
CH4	25
N2O	298

Metrics for Near Term Climate Forcers

Type	None
Time Horizon (YR)	100
VOC	0
CO	0
NOx	0
BC	0
OC	0

3) Carbon and Sulfur Ratios of Pollutants

Carbon ratio of VOC	0.85
Carbon ratio of CO	0.43
Carbon ratio of CH4	0.75
Carbon ratio of CO2	0.27
Sulfur ratio of SO2	0.50

Tacoma PUD Grid Mix Assumptions

2016 Source Report

https://www.mytpu.org/tacomapower/about-tacoma-power/dams-power-sources/

Tacoma Power produces or buys electricity from a number of different resources. We are providing you with information about the fuel used to generate the electricity you used in 2016, the most recent numbers available.

The State of Washington requires that electric utilities provide this information to customers on a regular basis. The Washington State Department of Commerce, Energy Office, publishes the information, based on reports from electric utilities.

Our Power Sources in 2016

Fuel Type	Percentage Used
Hydro Power	84%
Nuclear*	6%
Coal*	2%
Natural Gas	1%
Wind	7%

*Represents a portion of the power Tacoma Power gets from the Bonneville Power Administration.

Year	Region	Category	CO2	CH4	N2O	CO2E	Unit
2015	British Columbia	Natural Gas Production and Processing	9,071.7	68.5	0.24	10,855.9	kt
2015	British Columbia	Natural Gas Transmission and Storage	1,239.2	8.9	0.03	1,471.1	kt
2015	British Columbia	Natural Gas Distribution	14.7	3.4	0.00	100.7	kt

Provided by Frank Neitzert - Chief, Energy Section - Canada Science and Risk Assessment Directorate
In response to NIR data request on February 28, 2018

ATTACHMENT C
(SCENARIO B)

Scenario Definitions

Production End Uses (LNG gallons/year)	Scenario A	Scenario B
Total Production	91,250,000	91,250,000
On-site Peak Shaving	10,000,000	10,000,000
Gig Harbor Peak Shaving	0	1,825,000
On-road Trucking	0	3,650,000
TOTE Marine	39,000,000	39,000,000
Truck-to-Ship Bunkering	0	1,825,000
Other Marine (by Bunker Barge)	42,250,000	34,950,000

Scenario B	Project			No Project		
	Fuel Throughput (MMBTU/year)	Loss Factor	GHG Emissions (MT CO2e/year)	Fuel Throughput (MMBTU/year)	Loss Factor	GHG Emissions (MT CO2e/year)
Extraction, processing, and transmission to Sumas hub	**7,269,653**	**0.00%**	**59,563**	**1,175,291**	**0.00%**	**9,630**
Transmission from Sumas Hub to PSE gate	**7,266,233**	**0.05%**	**5,888**	**1,029,605**	**0.05%**	**834**
Distribution via PSE System	**7,259,336**	**0.095%**	**3,483**	**883,564**	**0.095%**	**424**
Liquefaction	**6,818,200**	**6.47%**	**36,800**	**0**		**0**
Direct Facility Emissions (includes Peak Shaving)	*6,818,200*		*34,483*	*0*		*0*
Electricity Supply	*6,818,200*		*2,317*	*0*		*0*
Vessel Loading of LNG	**5,680,341**		**12,207**	**0**		**0**
TOTE	*2,914,080*	0.011%	174	*0*		*0*
Bunker Barge	*2,611,464*	0.837%	11,848	*0*		*0*
Truck-to-Vessel	*154,797*	0.220%	185	*0*		*0*
On-road Heavy-duty Truck Fuel	**272,728**		**18,703**	**246,769**		**24,205**
LNG (Plant-to-Tank Emissions)	*271,446*	*0.47%*	*915*	*0*		*0*
LNG (Tank-to-Wheels Emissions)	*271,446*		*17,700*	*0*		*0*
ULSD (Well-to-Wheels Emissions)	*0*		*0*	*246,769*		*24,205*
Gig Harbor LNG Supply	**136,364**		**10**	**145,202**		**844**
Distribution (PSE or BC)	*Included above*		*Included above*	*145,187*	*0.010%*	*10*
Liquefaction	*Included above*		*Included above*	*136,364*	*6.47%*	*736*
LNG (Plant-to-Gig Harbor Emissions)	*136,364*		*10*	*136,364*		*98*
TOTE Vessel Operations	**3,001,172**		**235,355**	**6,002,344**		**340,146**
TOTE LNG (Direct Vessel Emissions)	*2,913,759*		*233,733*	*0*		*0*
TOTE Pilot Fuel Oil (Well-to-Tank Emissions)	*87,413*		*1,622*	*0*		*0*
TOTE Fuel Oil (Well-to-Tank Emissions)	*0*		*0*	*3,001,172*		*55,680*
TOTE Fuel Oil (Direct Vessel Emissions)	*0*		*0*	*3,001,172*		*284,466*
Other Vessel Operations	**2,667,307**		**209,173**	**2,667,307**		**302,306**
Other LNG (Direct Vessel Emissions)	*2,589,618*		*207,732*	*0*		*0*
Other Pilot Fuel Oil (Well-to-Tank Emissions)	*77,689*		*1,441*	*0*		*0*
Other Fuel Oil (Well-to-Tank Emissions)	*0*		*0*	*2,667,307*		*49,486*
Other Fuel Oil (Direct Vessel Emissions)	*0*		*0*	*2,667,307*		*252,821*
Total			**581,182**			**678,388**

ULSD Well-to-Tank Emissions (GREET 2017 defaults for Scenario Year 2018)

VOC	CO	NOx	PM10	PM2.5	SOx	BC	OC	CH4	N2O	CO2	CO2e
8.105	14.182	31.498	2.162	1.752	16.7	0.292	0.5	170.2	0.3	14,222	18,553

On-road Truck Emissions (GREET 2017 defaults for Scenario Year 2018)

Pathway Component	VOC	CO	NOx	BC	OC	CH_4	N_2O	CO_2	CO_2e	Loss Factor
Plant-to-Tank LNG Combination Tractor (g/MMBTU)	0.308	1.289	7.299	0.019	0.087	104.5	0.017	753.4	3,371	0.47%
Tank-to-Wheels LNG Combination Tractor (g/MMBTU)	21.07	1,167	66.09	0.358	0.587	248.9	0.026	58,975	65,205	0.00%
Well-to-Wheels Diesel Combination Tractor (g/MMBTU)	31.52	94.58	228.4	0.689	1.182	189.7	0.370	93,234	98,088	

Well-to-Wheels Energy Consumption, Water Consumption, and Emissions of Heavy-Duty Vehicles

Based on default GREET 2017 values for Scenario Year 2018

CIDI Combination Long-Haul Trucks: Conventional and LS Diesel

	Btu/mile or Gallon/mile or g/mile				Btu/mmBtu or Gallon/mmBtu or g/mmBtu			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	1,484	2,237	17,738	21,459	83,677	126,119	1,000,000	1,209,796
Fossil Fuels	1,415	2,206	17,738	21,359	79,746	124,380	1,000,000	1,204,126
Coal	184	84	0	268	10,377	4,728	0	15,105
Natural Gas	951	1,459	0	2,410	53,607	82,280	0	135,887
Petroleum	280	663	17,738	18,681	15,762	37,372	1,000,000	1,053,134
Water Consumption	0	0	0	0	18	5	0	23
CO2 (w/ C in VOC & CO)	111	141	1,402	1,654	6,277	7,939	79,019	93,234
CH4	3	0	0	3.365	148.852	21.363	19.517	189.731
N2O	0	0	0	0.007	0.109	0.145	0.116	0.370
GHGs	191	153	1,413	1,756	10,771	8,618	79,635	99,024
VOC: Total	0.071	0.072	0.415	0.559	4.023	4.082	23.413	31.519
CO: Total	0.159	0.093	1.426	1.678	8.953	5.234	80.390	94.578
NOx: Total	0.391	0.168	3.492	4.051	22.042	9.461	196.870	228.373
PM10: Total	0.022	0.017	0.117	0.156	1.227	0.935	6.621	8.783
PM2.5: Total	0.018	0.013	0.057	0.088	1.035	0.717	3.228	4.980
SOx: Total	0.171	0.125	0.010	0.306	9.656	7.044	0.545	17.244
BC Total	0.003	0.002	0.007	0.012	0.194	0.097	0.397	0.689
OC Total	0.007	0.003	0.012	0.021	0.384	0.146	0.653	1.182
VOC: Urban	0.012	0.042	0.179	0.233	0.684	2.357	10.068	13.109
CO: Urban	0.006	0.035	0.613	0.655	0.359	1.980	34.568	36.907
NOx: Urban	0.019	0.057	1.502	1.578	1.078	3.223	84.654	88.955
PM10: Urban	0.001	0.010	0.050	0.062	0.084	0.543	2.847	3.474
PM2.5: Urban	0.001	0.007	0.025	0.033	0.068	0.417	1.388	1.873
SOx: Urban	0.024	0.065	0.004	0.092	1.331	3.641	0.234	5.206
BC: Urban	0.000	0.001	0.003	0.004	0.009	0.052	0.171	0.231
OC: Urban	0.000	0.001	0.005	0.007	0.020	0.066	0.281	0.367

SI Combination Long-Haul Trucks: LNG, NA NG

	Btu/mile or Gallon/mile or g/mile				Btu/mmBtu or Gallon/mmBtu or g/mmBtu			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	1,539	2,495	19,709	23,743	78,086	126,599	1,000,000	1,204,685
Fossil Fuels	1,530	2,479	19,709	23,718	77,623	125,767	1,000,000	1,203,390
Coal	25	45	0	70	1,261	2,266	0	3,527
Natural Gas	1,426	2,297	19,709	23,432	72,353	116,557	1,000,000	1,188,910
Petroleum	79	137	0	216	4,009	6,945	0	10,954
Water Consumption	0	0	0	0	3	1	0	4
CO2 (w/ C in VOC & CO)	101	146	1,162	1,410	5,137	7,412	58,975	71,524
CH4	3	3	5	10.951	163.448	143.277	248.900	555.625
N2O	0	0	0	0.004	0.139	0.045	0.026	0.210
GHGs	199	231	1,310	1,739	10,078	11,722	66,449	88,248
VOC: Total	0.134	0.022	0.415	0.572	6.824	1.110	21.072	29.005
CO: Total	0.273	0.134	23.000	23.407	13.849	6.801	1,166.982	1,187.632
NOx: Total	0.368	0.247	1.303	1.918	18.672	12.544	66.094	97.310
PM10: Total	0.009	0.012	0.117	0.138	0.453	0.600	5.959	7.011
PM2.5: Total	0.008	0.011	0.057	0.076	0.405	0.560	2.905	3.870
SOx: Total	0.224	0.048	0.000	0.272	11.358	2.438	0.000	13.796
BC Total	0.003	0.001	0.007	0.011	0.143	0.044	0.358	0.545
OC Total	0.003	0.007	0.012	0.021	0.137	0.343	0.587	1.068
VOC: Urban	0.000	0.001	0.179	0.180	0.000	0.066	9.061	9.127
CO: Urban	0.000	0.012	9.890	9.902	0.000	0.605	501.802	502.407
NOx: Urban	0.000	0.024	0.560	0.584	0.000	1.226	28.421	29.647
PM10: Urban	0.000	0.001	0.050	0.052	0.000	0.063	2.562	2.625
PM2.5: Urban	0.000	0.001	0.025	0.026	0.000	0.059	1.249	1.308
SOx: Urban	0.000	0.006	0.000	0.006	0.000	0.323	0.000	0.323
BC: Urban	0.000	0.000	0.003	0.003	0.000	0.004	0.154	0.157
OC: Urban	0.000	0.001	0.005	0.006	0.000	0.034	0.253	0.287

3) Calculations of Energy Consumption, Water Consumption, and Emissions for Each Stage

Scenario Year: 2018

Grid Mix for Stationary Use: Tacoma PUD

	LNG Transportation and Distribution: As a Transportation Fuel	LNG Storage: As a Transportation Fuel	Plant-to-Tank Emissions
Energy efficiency			
Urban emission share	67.0%	70.0%	
Loss factor	1.003	1.011	
Share of feedstock input as feed (the remaining input as process fuel)			
Shares of process fuels			
Residual oil			
Diesel fuel			
Gasoline			
Natural gas			
Coal			
N-butane			
Hydrogen			
Electricity			
Feed loss			
Energy use: Btu/mmBtu of fuel throughput (except as noted)			
Residual oil			
Diesel fuel			
Gasoline			
Natural gas: process fuel			
Coal			
Natural gas: feed loss			
Natural gas flared			
N-butane			
Hydrogen			
Electricity			
Feedstock loss	538	4,186	4,724
Total energy	11,029	4,186	15,215
Fossil fuels	10,928	4,186	15,114
Coal	2	0	2
Natural gas	4,525	4,186	8,711
Petroleum	6,401	0	6,401
Water consumption	0.240	0.000	0.240
Total emissions: grams/mmBtu of fuel throughput			
VOC	0.308		0.308
CO	1.289		1.289
NOx	7.299		7.299
PM10	0.162		0.162
PM2.5	0.151		0.151
SOx	0.727		0.727
BC	0.019		0.019
OC	0.087		0.087
CH4: combustion	2.013		2.013
N2O	0.017		0.017
CO2	753		753
CH4: leakage	11.672	90.819	102.491
VOC evaporation			0.000
Misc. Items	58.358	230.256	288.614
Urban emissions: grams/mmBtu of fuel throughput			
VOC	0.042		0.042
CO	0.142		0.142
NOx	0.810		0.810
PM10	0.020		0.020
PM2.5	0.018		0.018
SOx	0.093		0.093
BC	0.002		0.002
OC	0.009		0.009

GREET Emissions Results (GREET 2017)

1. Well-to-Pump Energy Consumption, Water Consmption and Emissions: Btu or Gallon or g per mmBtu of Fuel Available at Fuel Station Pumps

	Baseline Conventional and LS Diesel
Total Energy	209,839
WTP Efficiency	82.7%
Fossil Fuels	204,179
Coal	15,074
Natural Gas	135,897
Petroleum	53,208
Water consumption	23
CO2 (w/ C in VOC & CO)	14,222
CH4	170.187
N2O	0.253
GHGs*	19,395
VOC	8.105
CO	14.182
NOx	31.498
PM10	2.162
PM2.5	1.752
SOx	16.719
BC	0.292
OC	0.529
VOC: Urban	3.041
CO: Urban	2.339
NOx: Urban	4.301
PM10: Urban	0.627
PM2.5: Urban	0.485
SOx: Urban	4.969
BC: Urban	0.060
OC: Urban	0.087

*GHG equivalent values calculated by GREET using AR5/100 GWPs. This value is not used in the model. Instead, CO2e values are calculated using emissions rates of the individual gases and their appropriate GWPs.

Summary (g/MMBTU)	CH4	N2O	CO2	CO2e
BC Production and Processing	45.5	0.16	6,030	7,216
BC Transmission	5.9	0.02	824	978
WA Transmission	13.679	0.295	377.793	810
PSE Distribution	19.2			480
Total				9,484

BC Province

2017 NIR: Table A12-11 (million tonnes CO2e)	2010	2011	2012	2013	2014	2015	Natural Gas Only (million tonnes of gas) CO2 (2015)	CH4 (2015)	N2O (2015)	CO2e(2015)
Natural Gas Production and Processing	10.4	11.7	11.8	12	12	10.9	9.07	0.069	0.0002388	10.9
Oil and Natural Gas Transmission	1.1	1.1	1	1.4	1.2	1.5	1.24	0.009	0.0000322	1.5
Natural Gas Distribution	0.1	0.1	0.1	0.1	0.1	0.1	0.01	0.003	0.0000004	0.1
Total	11.6	12.9	12.9	13.5	13.3	12.5	10.3	0.1	0.0	12.4

BC "Natural Gas Only" values are a subset of Canada's 2017 NIR, provided by Frank Neitzert - Chief, Energy Section - Canada Science and Risk Assessment Directorate

BC Distribution System		
Methane Emissions	3,438,658,571	grams CH4/year
Associated Energy Content	153,646	MMBTU
Loss Factor	0.010%	

BC Gas Production Volumes and Export Volumes (1000 m3)	2010	2011	2012	2013	2014	2015
Residue Gas Plant Outlet - BC Production Only	29,808,782	35,572,183	35,723,237	38,663,739	41,241,670	43,339,421

https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-gas-oil/production-statistics/gasnew.xls

Report does not specific standard or normal cubic meters. Assuming normal cubic meter

Natural Gas Heat Content	983	BTU/SCF
Cubic meters to cubic feet	35.3147	SCF/Nm3

BC Province

BC Natural Gas GHG Emissions (grams/MMBTU)	2010	2011	2012	2013	2014	2015	CO2 (2015)	CH4 (2015)	N2O (2015)	CO2e (2015)
Natural Gas Production and Processing	10,050	9,475	9,515	8,941	8,382	7,245	6,030	45.5	0.16	7,216
Oil and Natural Gas Transmission	1,063	891	806	1,043	838	997	824	5.9	0.02	978
Natural Gas Distribution	97	81	81	75	70	66	10	2.3	0.00	67
Total	11,210	10,446	10,402	10,058	9,290	8,308	6,863	53.7	0.18	8,260
Total Ex-Distribution	11,113	10,366	10,322	9,984	9,220	8,242	6,853	51.5	0.18	8,193

Washington State

Washington State Gas Transmission (g/MMBTU-mile)	VOC	CO	NOx	PM10	PM2.5	SOx	BC	OC	CH4	N2O	CO2
Pipeline Compression/Transport	0.0057	0.0293	0.0348	0.0001	0.0001	0.0005	0.0000	0.0000	0.0288	0.0020	2.6112
Methane Leakage									0.0657		
Transmission Distance	144.68	miles	Distance from FERC Form 567. Sumas interconnect to Frederickson Meter Station								

Washington State Gas Transmission (g/MMBTU)	VOC	CO	NOx	PM10	PM2.5	SOx	BC	OC	CH4	N2O	CO2	CO2e
Pipeline Compression/Transport	0.826	4.243	5.034	0.015	0.013	0.079	0.002	0.004	4.169	0.295	377.793	572.554
Methane Leakage	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	9.511	0.000	0.000	237.765
Total	0.826	4.243	5.034	0.015	0.013	0.079	0.002	0.004	13.679	0.295	377.793	810.319

Loss Factor

Leakage Rate 0.048% Gas lost through the system

9.511 gCH4/MMBTU

0.0000495 MMBTU/gCH4

0.05%

Washington State

PSE Distribution System Leakage Rate 0.095% Based on natural gas receipts. This includes lost and unaccounted for gas, of which leakage is only a portion.

0.0000495 MMBTU/gCH4

19.19 gCH4/MMBTU

479.8 gCO2e/MMBTU

GREET 2017 - Emissions for NG Transmission to LNG Plant.

Scenario year	2018
Transmission Distance	150 miles
Grid Mix	WECC

Natural Gas as a Feedstock to Produce Transportation Fuels	NG Transmission to LNG Plant (as a final transportation fuel)
Energy efficiency	
Urban emission share	2.0%
Loss factor	1.000
Share of feedstock input as feed (the remaining input as process fuel)	
Shares of process fuels	
Residual oil	
Diesel fuel	
Gasoline	
Natural gas	
Coal	
N-butane	
Hydrogen	
Electricity	
Feed loss	
Energy use: Btu/mmBtu of fuel throughput (except as noted)	
Residual oil	
Diesel fuel	
Gasoline	
Natural gas: process fuel	
Coal	
Natural gas: feed loss	
Natural gas flared	
N-butane	
Hydrogen	
Electricity	
Feedstock loss	478
Total energy	7,322
Fossil fuels	7,261
Coal	108
Natural gas	7,127
Petroleum	27
Water consumption	0.057
Total emissions: grams/mmBtu of fuel throughput	
VOC	0.857
CO	4.399
NOx	5.219
PM10	0.016
PM2.5	0.013
SOx	0.082
BC	0.003
OC	0.004
CH4: combustion	4.322
N2O	0.306
CO2	392
CH4: leakage	9.860
VOC evaporation	
Misc. Items	
Urban emissions: grams/mmBtu of fuel throughput	
VOC	0.115
CO	0.607
NOx	0.721
PM10	0.003
PM2.5	0.002
SOx	0.005
BC	0.000
OC	0.001

Gig Harbor LNG Supply

Baseline - Delivery from Fortis by truck		
NG Extraction, Processing, and Transmission to Sumas	8,193	gCO2e/MMBTU
BC Distribution System	67	gCO2e/MMBTU
Liquefaction	5,397	gCO2e/MMBTU
Transport by Tanker Truck	718	gCO2e/MMBTU
Transport Distance	175	miles
Energy Consumption	17,738	BTU/mile
Well-to-Wheels GHG Emissions Rate	98,088	gCO2e/MMBTU
Tanker Capacity	10,000	gallons
Tanker Capacity	848.2	MMBTU
Total Production and Transport	**14,376**	**gCO2e/MMBTU**

Project - Delivery from PSE by truck		
NG Extraction, Processing, and Transmission to Sumas	8,193	gCO2e/MMBTU
Transmission to PSE System	810	gCO2e/MMBTU
PSE System Distribution	480	gCO2e/MMBTU
Liquefaction	5,397	gCO2e/MMBTU
Transport by Tanker Truck	70	gCO2e/MMBTU
Transport Distance	17	miles
Energy Consumption	17,738	BTU/mile
Well-to-Wheels GHG Emissions Rate	98,088	gCO2e/MMBTU
Tanker Capacity	10,000	gallons
Tanker Capacity	848.2	MMBTU
Total Production and Transport	**14,951**	**gCO2e/MMBTU**

Summary	**gCO2e/MMBTU LNG produced**
Direct Emissions	5,058
Electricity (Upstream) Emissions	339.81
Total	5,397

PSE Facility: Direct Emissions

Fuel Production 250,000 gallons per day

Case	Units	VOC	CO	NOx	PM10	PM2.5	SOx	BC	OC	CH4	N2O	CO2	CO2e
May 2018 update to Nov 21 PTE	tons/year	48.81	12.27	3.83		1.27	9.14	0.21	0.54	44.75	0.06	36,829	38,011
May 2018 update to Nov 21 PTE	grams/MMBTU	6.494	1.633	0.510	0.000	0.169	1.216	0.028	0.072	5.955	0.007	4,900	5,058

PSE Facility: Electricity Supply Emissions

Electricity Demand	123,455,000	kWh/year @ 10 million gpy production under PTE
kWh to MMBTU	293	kWh/MMBTU
Electricity Demand	421,246	MMBTUe/year

Facility Emissions from Tacoma PUD Supply		VOC	CO	NOx	PM10	PM2.5	SOx	BC	OC	CH4	N2O	CO2	CO2e
Upstream Electricity Emissions	grams/MMBTUe	0.649	1.631	3.833	0.728	0.314	11.621	0.023	0.050	10.917	0.092	5,942	6,244
Annual Electricity-related Emissions	grams/year	273,551	687,243	1,614,636	306,799	132,470	4,895,272	9,610	20,976	4,598,716	38,661	2,503,064,548	2,630,080,543
Annual Electricity-related Emissions	g/MMBTU LNG	0.040	0.101	0.237	0.045	0.019	0.718	0.0014	0.0031	0.674	0.006	367.12	339.81

PSE Facility: Natural Gas Supply

MMBTU of supply per MMBTU of LNG produced	106%
Loss Factor	6.47%

			Scenario B
Production End Uses (LNG gallons/year)	**Scenario A**	**Scenario B**	**Current Scenario**
Total Production	91,250,000	91,250,000	91,250,000
On-site Peak Shaving	10,000,000	10,000,000	10,000,000
Gig Harbor Peak Shaving	0	1,825,000	1,825,000
On-road Trucking	0	3,650,000	3,650,000
TOTE Marine	39,000,000	39,000,000	39,000,000
Truck-to-Ship Bunkering	0	1,825,000	1,825,000
Other Marine (by Bunker Barge)	42,250,000	34,950,000	34,950,000

GREET 2017 - Emissions for Delivered Electricity

Scenario year 2018
Grid Mix Tacoma PUD

9) Fuel-Cycle Energy Use, Water Consumption, and Emissions of Electric Generation: Btu or Gallons or Grams per mmBtu of Electricity Available at User Sites (wall outlets)

	Stationary Use: User Defined Mix			
	Total		Urban	
	Feedstock	Fuel	Feedstock	Fuel
Total energy	4,193	1,108,653		
Fossil fuels	3,286	65,872		
Coal	67	44,529		
Natural gas	2,273	21,343		
Petroleum	946	0		
Water consumption	2.276	1,177.196		
VOC	0.564	0.085	0.012	0.029
CO	0.823	0.809	0.042	0.271
NOx	1.480	2.353	0.077	0.850
PM10	0.408	0.320	0.002	0.119
PM2.5	0.080	0.234	0.001	0.087
SOx	0.558	11.063	0.009	4.200
BC	0.009	0.013	0.000	0.005
OC	0.017	0.033	0.001	0.011
CH4	10.846	0.071		
N2O	0.019	0.073		
CO2	221	5,721		
CO2 (w/ C in VOC & (	224	5,723		
GHGs	554	5,744		

LNG Bunkering Emissions

https://www.marad.dot.gov/wp-content/uploads/pdf/Methane-emissions-from-LNG-bunkering-20151124-final.pdf

Summary	**Methane Emissions Rate (gCH4/MMBTU delivered)**	**GHG Emissions Rate (gCO2e/MMBTU delivered)**	**Fraction of Gas Delivered by this Process**
Ship/Barge Loading	2.4	60.16	98%
Bunker Vessel Storage	131.2	3,281	46%
Truck/Ship-to-Ship Transfe	47.8	1,196	49%
Total	181.5	2,152	

Loss Factor 0.3968% Gas lost through the system

Net Delivered LNG 380,000 gallons per typical bunkering event

Bunker Barge Loading

Vapor Displaced		Recovery Rate	Loss per Bunkering Event	Volume per Bunkering Event (gallons)	Volume Lost per Bunkering Event (gallons)	Methane Emissions Rate (gCH4/MMBTU)	GHG Emissions Rate (gCO2e/MMBTU)
0.22%		95%	0.011%	383,179	42.1	2.4	60.16

Bunker Vessel Storage

Boil off rate (%/day)	Duration (days)	Recovery Rate	Loss per Bunkering Event	Volume per Bunkering Event (gallons)	Volume Lost per Bunkering Event (gallons)	Methane Emissions Rate (gCH4/MMBTU)	GHG Emissions Rate (gCO2e/MMBTU)
0.15%	4	0%	0.60%	383,137	2,299	131.2	3,281

Ship-to-Ship Transfer

Vapor Displaced		Recovery Rate	Loss per Bunkering Event	Volume per Bunkering Event (gallons)	Volume Lost per Bunkering Event (gallons)	Methane Emissions Rate (gCH4/MMBTU)	GHG Emissions Rate (gCO2e/MMBTU)
0.22%		0%	0.22%	380,838	838	47.8	1,196

End Uses	**Volume (LNG gallons/year)**	**Loss Factor**	**Methane Emissions (LNG Gallons/year)**	**Methane Emissions (gCH4/year)**
TOTE	39,000,000	0.0110%	4,290	6,954,855
Other Bunker Barge	34,950,000	0.8365%	292,367	473,927,125
Truck-to-Ship Bunkering	1,825,000	0.2205%	4,024	6,522,665
Total	75,775,000	0.3968%	300,681	487,404,644

Summary	**gCO2e/MMBTU**
Vessel Operations	75,003

TOTE Vessel Emissions

Estimate from model based on Puget Sound Maritime Emissions Inventory methodology

Ship Emissions and Fuel Consumption Estimates

Inputs

Route Definition

Ship Type	Origin	Destination	Distance at Sea (nm)	Transit Speed (knots)	Transit Time (hours)	Maneuvering Time (hours)	Time at Berth (Origin - hours)	Time at Berth (Destination - hours)	Time within 200 nm: Transit	Time within 200 nm: Manuvering	Time within 200 nm: Hotelling
RoRo	Anchorage	Tacoma	1450	22	65.9	2	10	0	14%	50%	50%

Vessel Details

Service Speed (knots)	Max Speed (knots)	Installed Power (kW)	Main Engine Speed (RPM)	Aux Engine Speed (RPM)	Main Engine Type	Aux Engine Type	Boiler Type
24	25.5	52200	400	720	Low Pressure DF LNG All	Low Pressure DF LNG All	LNG Aux Boiler All

Mode	Time	Main Engine Load (kW)	Aux Engine Load (kW)	Aux Boiler Load (kW)	Fuel - In ECA	Fuel - Outside ECA
Transit	65.9	33396	514	0	LNG	LNG
Manuvering	2	1044	1541	275	LNG	LNG
Hotelling	10	0	890	275	LNG	LNG

Total Emissions (tons per trip)

	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4	BC	OC	CO2e
Transit	4.68	0.00	4.68	0.24	0.05	0.05	0.00	1094	0.08	13.06	0.01	0.02	1,445
Manuvering	0.03	0.00	0.05	0.00	0.00	0.00	0.00	3	0.00	0.03	0.00	0.00	4
Hotelling	0.03	0.00	0.02	0.00	0.00	0.00	0.00	6	0.00	0.05	0.00	0.00	8
Total Emissions (tons)	4.73	0.00	4.75	0.24	0.05	0.05	0.00	1103	0.08	13.14	0.01	0.02	1,457
Emissions Rate (g/kWh)	1.91	0.00	1.91	0.10	0.02	0.02	0.00	444	0.03	5.29	0.00	0.01	587
Emissions Rate (g/MMBTU HFOe, HHV basis)	243.7	0.1	244.5	12.4	2.7	2.7	0.0	56801	4.0	676.5	0.5	1.2	75,003
Emissions Rate (g/MMBTU LNG, LHV basis)	260.7	0.1	261.5	13.3	2.9	2.9	0.0	60750	4.2	723.6	0.6	1.2	80,217

At 5.3 g/kWh methane slip

NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4
4.68	0.00	4.68	0.24	0.05	0.05	0.00	1094	0.08	13.06
0.03	0.00	0.05	0.00	0.00	0.00	0.00	3	0.00	0.03
0.03	0.00	0.02	0.00	0.00	0.00	0.00	6	0.00	0.05
4.73	0.00	4.75	0.24	0.05	0.05	0.00	1103	0.08	13.14
1.91	0.00	1.91	0.10	0.02	0.02	0.00	444	0.03	5.29
243.7	0.1	244.5	12.4	2.7	2.7	0.0	56801	4.0	676.5

Summary	**gCO2e/MMBTU**
Vessel Operations	88,624

TOTE Vessel Emissions

Estimate from model based on Puget Sound Maritime Emissions Inventory methodology

Ship Emissions and Fuel Consumption Estimates

Inputs

Route Definition

Ship Type	Origin	Destination	Distance at Sea (nm)	Transit Speed (knots)	Transit Time (hours)	Maneuvering Time (hours)	Time at Berth (Origin - hours)	Time at Berth (Destination - hours)	Time within 200 nm: Transit	Time within 200 nm: Manuvering	Time within 200 nm: Hotelling
RoRo	Anchorage	Tacoma	1450	22	65.9	2	10	0	14%	50%	50%

Vessel Details

Service Speed (knots)	Max Speed (knots)	Installed Power (kW)	Main Engine Speed (RPM)	Aux Engine Speed (RPM)	Main Engine Type	Aux Engine Type	Boiler Type
24	25.5	52200	400	720	Medium speed diesel 2000 - 2010	Medium speed diesel 2000 - 2010	Fuel Oil Aux Boiler All

Mode	Time	Main Engine Load (kW)	Aux Engine Load (kW)	Aux Boiler Load (kW)	Fuel - In ECA	Fuel - Outside ECA	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4	BC	OC	CO2e
							Total Emissions (tons per trip)												
Transit	65.9	33396	514	0	MGO (0.1% S)	MGO (0.1% S)	30.11	1.23	2.71	1.05	0.63	0.50	0.63	1683	0.07	0.02	0.41	0.09	1,707
Manuvering	2	1044	1541	275	MGO (0.1% S)	MGO (0.1% S)	0.17	0.03	0.03	0.00	0.00	0.00	0.00	4	0.00	0.00	0.00	0.00	5
Hotelling	10	0	890	275	MGO (0.1% S)	MGO (0.1% S)	0.13	0.01	0.01	0.01	0.00	0.00	0.00	10	0.00	0.00	0.00	0.00	10
						Total Emissions (tons)	30.40	1.26	2.75	1.06	0.63	0.51	0.63	1697	0.07	0.02	0.41	0.09	1,721
						Emissions Rate (g/kWh)	12.25	0.51	1.11	0.43	0.25	0.20	0.25	683	0.03	0.01	0.17	0.04	693
						Emissions Rate (g/MMBTU HFOe, HHV basis)	1565.5	65.0	141.6	54.5	32.5	26.0	32.5	87363	3.7	1.3	21.2	4.7	88,624
						Emissions Rate (g/MMBTU HFO, LHV basis)	1674.3	69.6	151.4	58.3	34.8	27.8	34.8	93437	4.0	1.4	22.6	5.0	94,785

4) Mass fractions of black carbon and organic carbon emissions of corresponding PM2.5 emission factors

4.1) Stationary, mobile, and open burning emission sources, %

	Natural gas						Coal		Biomass			Diesel							
	Boiler	Engine	Combined	Simple cy	Nonroad E	Flared	Boiler	IGCC	Industrial,	IGCC	Open burn	Industrial,	Simple cy	Engine	Nonroad v	Nonroad E	Locomotiv	HDDT 8b	HDDT 6
BC	16.5	20.0	2.9	2.9	9.8	95.0	4.3	4.3	13.8	13.8	12.1	10.0	10.0	81.3	56.3	77.1	8.4	16.0	8.1
OC	42.8	42.8	68.0	68.0	83.7	5.0	8.1	8.1	32.6	32.6	33.9	25.0	25.0	18.1	34.9	21.1	88.6	66.0	88.0

	Gasoline			Residual fuel oil				Crude oil	Biochar	Jet fuel	
	Engine	Off-road v	Nonroad E	Boiler	Engine	Simple cy	Ocean tan	Boiler	Boiler	Cruise	Landing and take-offs
BC	10.0	13.6	9.8	6.3	15.0	6.0	15.0	2.9	6.2	31.3	35.8
OC	32.0	86.4	83.7	4.4	39.0	4.0	39.0	2.1	79.9	30.3	26.0

Specifications of Fuels, Global Warming Potentials of Greenhouse Gases, and Carbon and Sulfur Ratios of Pollutants

1) Specifications of Fuels

Fuel	Heating Value			Density	C ratio	S ratio	S ratio			
	Calculation: LHV	LHV	HHV		(% by wt)	(ppm by wt)	Actual ratio by wt	LHV/HHV		
Use LHV or HHV in calculations?	1	1 -- LHV; 2 -- HHV								
Liquid Fuels:	**Btu/gal**	**Btu/gal**	**Btu/gal**	**grams/gal**					grams/MMBTU	
Crude oil	129,670	129,670	138,350	3,205	85.3%	16,000	0.016000	0.937		
Synthetic crude oil (SCO)	135,085	135,085	144,476	3,266	85.6%	1,800	0.001800	0.935		
Bitumen	152,371	152,371	162,964	3,840	83.0%	48,000	0.048000	0.935		
Dilbit (After Recovery)	152,371	152,371	162,964	3,840	83.0%	48,000	0.048000	0.935		
Dilbit (Before Recovery)	145,194	145,194	155,288	3,500	83.2%	37,227	0.037227	0.935		
Diluent	128,449	128,449	137,378	2,709	84.1%	1,600	0.001600	0.935		
Shale Oil (Bakken)	125,601	125,601	134,009	3,087	0.853	16000	0.016000	0.937		
Shale Oil (Eagle Ford)	122,493	122,493	130,692	2,984	0.853	16000	0.016000	0.937		
Gasoline blendstock	116,090	116,090	124,340	2,819	86.3%	10	0.000010	0.934		
Gasoline	112,194	112,194	120,439	2,836	82.8%	9	0.000009	0.932		
CA gasoline	112,194	112,194	120,439	2,836	82.8%	9	0.000009	0.932		
High Octane Fuel (E25)	106,150	106,150	114,388	2,861	77.8%	8	0.000008	0.928		
High Octane Fuel (E40)	100,186	100,186	108,416	2,887	72.7%	6	0.000006	0.924		
U.S. conventional diesel	128,450	128,450	137,380	3,167	86.5%	200	0.000200	0.935		
CA diesel	129,488	129,488	138,490	3,206	87.1%	11	0.000011			
Diesel for non-road engines	128,450	128,450	137,380	3,167	86.5%	11	0.000011	0.935		
Low-sulfur diesel	129,488	129,488	138,490	3,206	87.1%	11	0.000011	0.935		
Petroleum naphtha	116,920	116,920	125,080	2,745	85.0%	1	0.000001	0.935		
Low Octane Gasoline-Like Fuel (LOF)	118,237	118,237	126,586	2,834	85.3%	10	0.000010	0.934		
Conventional Jet Fuel	124,307	124,307	132,949	3,036	86.2%	700	0.000700	0.935		
ULS Jet Fuel	123,041	123,041	131,595	2,998	86.0%	11	0.000011	0.935		
NG-based FT naphtha	111,520	111,520	119,740	2,651	84.2%	0	0.000000	0.931		
Residual oil	140,353	140,353	150,110	3,752	86.8%	5,000	0.005000	0.935		
Bunker fuel for ocean tanker	140,353	140,353	150,110	3,752	86.8%	27,000	0.027000	0.935		
Methanol	57,250	57,250	65,200	3,006	37.5%	0	0.000000	0.878		
Ethanol	76,330	76,330	84,530	2,988	52.2%	1	0.000001	0.903		
Butanol	99,837	99,837	108,458	3,065	64.9%	0	0.000000	0.921		
Acetone	83,127	83,127	89,511	2,964	62.0%	0	0.000000	0.929		
E-Diesel Additives	116,090	116,090	124,340	2,819	86.3%	10	0.000010	0.934		
Liquefied petroleum gas (LPG)	84,950	84,950	91,410	1,923	82.0%	0	0.000000	0.929		
Liquefied natural gas (LNG)	74,720	74,720	84,820	1,621	75.0%	0	0.000000	0.881	21694.33 g/MMBTU LHV	6818200
Dimethyl ether (DME)	68,930	68,930	75,610	2,518	52.2%	0	0.000000	0.912		
Dimethoxy methane (DMM)	72,200	72,200	79,197	3,255	47.4%	0	0.000000	0.912		
Methyl ester (biodiesel, BD)	119,550	119,550	127,960	3,361	77.6%	0	0.000000	0.934		
Fischer-Tropsch diesel (FTD)	123,670	123,670	130,030	3,017	85.3%	0	0.000000	0.951		
Renewable Diesel I (SuperCetane)	117,059	117,059	125,294	2,835	87.1%	0	0.000000	0.934		
Renewable Diesel II (UOP-HDO)	122,887	122,887	130,817	2,948	87.1%	0	0.000000	0.939		
Renewable Diesel III (PNNL-HTL)	123,542	123,542	133,070	3,003	87.1%	0	0.000000	0.928		
Renewable Gasoline	115,983	115,983	124,230	2,830	84.0%	0	0.000000	0.934		
Renewable Gasoline (IDL)	111,560	111,560	119,493	2,655	83.4%	10	0.000010	0.934		
SPK (FT Jet Fuel/HRJ)	119,777	119,777	128,103	2,866	84.7%	0	0.000000	0.935		
Liquid hydrogen	30,500	30,500	36,020	268	0.0%	0	0.000000	0.847		
Methyl tertiary butyl ether (MTBE)	93,540	93,540	101,130	2,811	68.1%	0	0.000000	0.925		
Ethyl tertiary butyl ether (ETBE)	96,720	96,720	104,530	2,810	70.6%	0	0.000000	0.925		
Tertiary amyl methyl ether (TAME)	100,480	100,480	108,570	2,913	70.6%	0	0.000000	0.925		
Butane	94,970	94,970	103,220	2,213	82.8%	0	0.000000	0.920		
Isobutane	90,060	90,060	98,560	2,118	82.8%	0	0.000000	0.914		
Isobutylene	95,720	95,720	103,010	2,253	85.7%	0	0.000000	0.929		
Propane	84,250	84,250	91,420	1,920	81.8%	0	0.000000	0.922		
Natural gas liquids	83,686	83,686	90,050	2,532		0	0.000000	0.929		
n-Hexane	105,125	105,125	112,166	2,479	83.6%	0	0.000000	0.937		
Gaseous Fuels (at 32F and 1atm):	**Btu/ft3**	**Btu/ft3**	**Btu/ft3**	**gms/ft3**				**LHV/HHV**		
Natural gas	983	983	1,089	22.0	72.4%	6	0.000006	0.903		
Pure Methane	962	962	1,068	20.3	75.0%	0	0.000000	0.901		
Gaseous hydrogen	290	290	343	2.6	0.0%	0	0.000000	0.845		
Carbon Dioxide				56.0	27.3%	0	0.000000			
Still gas (in refineries)	982	982	1,044	20.3	75.8%	6	0.000006	0.941		
Solid Fuels:	**Btu/ton**	**Btu/ton**	**Btu/ton**					**LHV/HHV**		
Coal Mix for Electricity Generation	19,474,169	19,474,169	20,673,610		58.6%	10,456	0.010456			
Bituminous coal	22,639,320	22,639,320	23,633,493		61.2%	15,352	0.015352	0.958		
Subbituminous coal	16,085,444	16,085,444	17,449,320		53.7%	3,568	0.003568	0.922		
Lignite coal	10,805,183	10,805,183	12,992,302		49.1%	9,064	0.009064	0.832		
Synthetic coal	22,639,320	22,639,320	23,633,493		80.6%	16,143	0.016143	0.958		
Waste coal	9,945,646	9,945,646	11,958,783		32.6%	9,064	0.009064	0.832		
Pet Coke	26,949,429	26,949,429	28,595,925		86.7%	45,138	0.045138	0.942		
Tire Derived Fuel	26,664,354	26,664,354	28,293,434		48.8%	45,138	0.045138	0.942		
Coking coal	24,599,422	24,599,422	25,679,670		74.7%	11,800	0.011800	0.958		
Catalyst Coke	28,385,750	28,385,750	30,120,000		86.4%	45,138	0.045138	0.942		
Willow	15,396,000	15,396,000	16,524,000		48.7%	500	0.000500	0.932		
Poplar	15,929,000	15,929,000	17,062,000		50.1%	200	0.000200	0.934		
Switchgrass	14,447,000	14,447,000	15,583,000		46.6%	1,100	0.001100	0.927		
Miscanthus	15,342,000	15,342,000	16,377,000		47.6%	800	0.000800	0.937		
Corn stover	14,716,000	14,716,000	15,774,000		46.7%	1,000	0.001000	0.933		
Forest residue	17,289,000	17,289,000	17,906,000		50.3%	400	0.000400	0.966		
Clean Pine	15,929,000	15,929,000	17,062,000		50.1%	200	0.000200	0.934		
Yard trimming waste	15,000,000	15,000,000			47.8%	400	0.000400			
Sugarcane straw	13,454,049	13,454,049	15,774,000		50.0%			0.853		
Sugarcane bagasse	12,381,771	12,381,771	14,062,678		46.3%			0.880		
Bio-char	18,916,911	18,916,911	18,916,911		51.2%	0	0.000000	1.000		
Grain sorghum bagasse	12,781,599	12,781,599	14,131,556		39.3%	0	0.000000	0.904		
Sweet sorghum bagasse	14,409,931	14,409,931	15,305,245		42.0%	0	0.000000	0.942		
Forage sorghum bagasse	14,409,931	14,409,931	15,305,245		42.0%	0	0.000000	0.942		
Municipal solid waste (defined by EISA)	11,209,639	11,209,639	13,583,445		49.2%	1,765	0.001765	0.825		
Convertible municipal solid waste	14,155,275	14,155,275	16,144,033		50.5%	1,787	0.001787	0.877		

2) Global Warming Potentials of Greenhouse Gases: relative to CO2

Metrics for Carbon Dioxide, Methane, Nitrous Oxide

AR Edition/Type	AR4/GWP
Time Horizon (YR)	100
CO2	1
CH4	25
N2O	298

Metrics for Near Term Climate Forcers

Type	None
Time Horizon (YR)	100
VOC	0
CO	0
NOx	0
BC	0
OC	0

3) Carbon and Sulfur Ratios of Pollutants

Carbon ratio of VOC	0.85
Carbon ratio of CO	0.43
Carbon ratio of CH4	0.75
Carbon ratio of CO2	0.27
Sulfur ratio of SO2	0.50

Tacoma PUD Grid Mix Assumptions

2016 Source Report

https://www.mytpu.org/tacomapower/about-tacoma-power/dams-power-sources/

Tacoma Power produces or buys electricity from a number of different resources. We are providing you with information about the fuel used to generate the electricity you used in 2016, the most recent numbers available.

The State of Washington requires that electric utilities provide this information to customers on a regular basis. The Washington State Department of Commerce, Energy Office, publishes the information, based on reports from electric utilities.

Our Power Sources in 2016

Fuel Type	Percentage Used
Hydro Power	84%
Nuclear*	6%
Coal*	2%
Natural Gas	1%
Wind	7%

*Represents a portion of the power Tacoma Power gets from the Bonneville Power Administration.

Year	Region	Category	CO2	CH4	N2O	CO2E	Unit
2015	British Columbia	Natural Gas Production and Processing	9,071.7	68.5	0.24	10,855.9	kt
2015	British Columbia	Natural Gas Transmission and Storage	1,239.2	8.9	0.03	1,471.1	kt
2015	British Columbia	Natural Gas Distribution	14.7	3.4	0.00	100.7	kt

Provided by Frank Neitzert - Chief, Energy Section - Canada Science and Risk Assessment Directorate
In response to NIR data request on February 28, 2018

ATTACHMENT D

Emissions Factors and Activity Assumptions

Source: Puget Sound Maritime Air Emissions Inventory, 2012 (unless otherwise noted)

http://www.pugetsoundmaritimeairforum.org/uploads/PV_FINAL_POT_2011_PSEI_Report__7_Oct_12__MASTER_scg.pdf

OGV Emissions Factors and Activity

Table 3.12: Emission Factors for OGV Main Engines Using RO, g/kW-hr

Engine	Model Year	Key	NOx	VOC	CO	SO2	PM10	PM2.5	DPM
Slow speed diesel	< 1999	Slow speed dies	18.1	0.6	1.4	10.5	1.5	1.2	1.5
Medium speed diesel	< 1999	Medium speed d	14	0.5	1.1	11.5	1.5	1.2	1.5
Slow speed diesel	2000 - 2010	Slow speed dies	17	0.6	1.4	10.5	1.5	1.2	1.5
Medium speed diesel	2000 - 2010	Medium speed d	13	0.5	1.1	11.5	1.5	1.2	1.5
Slow speed diesel	2011 - 2015	Slow speed dies	14.4	0.6	1.4	10.5	1.5	1.2	1.5
Medium speed diesel	2011 - 2015	Medium speed d	10.5	0.5	1.1	11.5	1.5	1.2	1.5
Lean Burn SI LNG	All	Lean Burn SI LNG	0.9	0.0	1.7	0	0.02	0.02	0
Low Pressure DF LNG	All	Low Pressure DF	1.9	0.0	1.9	0.10	0.02	0.02	0
Gas turbine	All	Gas turbine All	6.1	0.1	0.2	16.5	0.05	0.04	0
Steamship	All	Steamship All	2.1	0.1	0.2	16.5	0.8	0.6	0

Medium speed means RPM>130

Table 3.13: GHG Emission Factors for OGV Main Engines Using RO, g/kW-hr

Engine Model Year	Model Year	Key	CO2	N2O	CH4
Slow speed diesel	< 1999	Slow speed diesel	620	0.031	0.012
Medium speed diesel	< 1999	Medium speed die	683	0.031	0.01
Slow speed diesel	2000 - 2010	Slow speed diesel	620	0.031	0.012
Medium speed diesel	2000 - 2010	Medium speed die	683	0.031	0.01
Slow speed diesel	2011 - 2015	Slow speed diesel	620	0.031	0.012
Medium speed diesel	2011 - 2015	Medium speed die	683	0.031	0.01
Gas turbine	All	Gas turbine All	970	0.08	0.002
Steamship	All	Steamship All	970	0.08	0.002
Lean Burn SI LNG	All	Lean Burn SI LNG	472	0.031	4.1
Low Pressure DF LNG	All	Low Pressure DF L	444	0.031	5.3

N2O emissions factors for LNG engines assumed to be equal to medium speed diesel

LNG emissions factors from "GHG and NOx Emissions from Gas Fueled Engines", SINEF, 2017. PM emissions based on EPA certification data of 2017 Wartsila DF engine (rated at 8MW).

VOC emissions for LNG engines are estimated as NMVOC, based on a typical ratio of 3.8% NMVOC/CH4 emissions, as described in "Methane Emissions from Natural Gas Bunkering Operations in the Marine Sector", MARAD, 2015

https://www.nho.no/siteassets/nhos-filer-og-bilder/filer-og-dokumenter/nox-fondet/dette-er-nox-fondet/presentasjoner-og-rapporter/methane-slip-from-gas-engines-mainreport-1492296.pd

https://www.marad.dot.gov/wp-content/uploads/pdf/Methane-emissions-from-LNG-bunkering-20151124-final.pdf

Sulfur emissions rates for Low Pressure DF LNG engines based on SINEF report (Table 5.1) indicating 95-98% SOx reductions from LNG operation relative to MGO. Assume pilot fuel is MGO with a 0.5% sulfur content based on 2020 global sulfur cap

Table 3.16: Low-Load Adjustment Multipliers for Emission Factors

Load	NOx	HC	CO	PM
2%	4.63	21.18	9.68	7.29
3%	2.92	11.68	6.46	4.33
4%	2.21	7.71	4.86	3.09
5%	1.83	5.61	3.89	2.44
6%	1.6	4.35	3.25	2.04
7%	1.45	3.52	2.79	1.79
8%	1.35	2.95	2.45	1.61
9%	1.27	2.52	2.18	1.48
10%	1.22	2.2	1.96	1.38
11%	1.17	1.96	1.79	1.3
12%	1.14	1.76	1.64	1.24
13%	1.11	1.6	1.52	1.19
14%	1.08	1.47	1.41	1.15
15%	1.06	1.36	1.32	1.11
16%	1.05	1.26	1.24	1.08
17%	1.03	1.6	1.17	1.06
18%	1.02	1.18	1.11	1.04
19%	1.01	1.11	1.05	1.02
20%	1	1	1	1

Table 3.17: Composite Maneuvering Load Factors

Vessel Type	Load In	Load Out
Auto Carrier	0.04	0.06
Bulk	0.04	0.05
Containership	0.03	0.03
Cruise	0.03	0.04
General Cargo	0.03	0.04
ITB	0.04	0.06
Reefer	0.02	0.03
RoRo	0.02	0.02
Tanker	0.03	0.05

Table 3.18: Auxiliary Engine Emission Factors, g/kW-hr

Engine	Model Year	Key	NOx	VOC	CO	SO2	PM10	PM2.5	DPM
Medium speed diesel	≤ 1999	Medium speed d	14.7	0.5	1.1	12.3	1	0.8	1
Medium speed diesel	2000 - 2010	Medium speed d	13	0.5	1.1	12.3	1	0.8	1
Medium speed diesel	2011 - 2015	Medium speed d	10.5	0.5	1.1	12.3	1	0.8	1
Lean Burn SI LNG	All	Lean Burn SI LNG	0.9	0.0	1.7	0	0.02	0.02	0
Low Pressure DF LNG	All	Low Pressure DF	1.9	0.0	1.9	0.097125	0.02	0.02	0

LNG emissions factors for aux engines assumed to be equivalent to main engine emissions factors as both the main and aux engines are medium speed

Table 3.19: Greenhouse Gas Emission Factors for Auxiliary Engines, g/kW-hr

Engine	Model Year	Key	CO2	N2O	CH4
Medium speed diesel	All	Medium speed die	683	0.031	0.008
Medium speed diesel	2000 - 2010	Medium speed die	683	0.031	0.008
Medium speed diesel	2011 - 2015	Medium speed die	683	0.031	0.008
Lean Burn SI LNG	All	Lean Burn SI LNG	472	0.031	4.1
Low Pressure DF LNG	All	Low Pressure DF L	444	0.031	5.3

Table 2.14: Auxiliary Boiler Emission Factors using 2.7% S HFO, g/kW-hr

Engine	Model Year	Key	NOx	VOC	CO	SO2	PM10	PM2.5	DPM
Fuel Oil Aux Boiler	All	Fuel Oil Aux Boil	2.1	0.1	0.2	16.5	0.8	0.64	0.8
LNG Aux Boiler	All	LNG Aux Boiler A	2.1	0.1	0.2	0	0.8	0.64	0

Source: 2013 POLB Emissions Inventory

Table 2.14: Auxiliary Boiler GHG Emission Factors using 2.7% S HFO, g/kW-hr

Engine	Model Year	Key	CO2	N2O	CH4
Fuel Oil Aux Boiler	All	Fuel Oil Aux Boiler	970	0.08	0.002
LNG Aux Boiler	All	LNG Aux Boiler All	677	0.08	0.002

Source: 2013 POLB Emissions Inventory

CO2 emissions for LNG based on ratios of carbon-per-BTU for bunker fuel and natural gas, as given in ANL GREET's fuel properties worksheet
N2O emissions for LNG assumed to be equal to fuel oil. CH4 emissions for LNG scaled based on fuel oil emissions and ratios of CH4 emissions from medium speed FO and LNG engines.

Table 3.20: 2011 Auxiliary Engine Power and Load Defaults, kW

Vessel Type	Sea	Maneuvering	Hotelling
Auto Carrier	514	1541	876
Bulk	266	705	157
Bulk - Self Discharging	439	1163	258
Bulk - Heavy Load	231	610	136
Bulk - Wood Chips	266	705	157
Container - 1000	492	1556	536
Container - 2000	723	1916	945
Container - 3000	710	2382	965
Container - 4000	1162	2973	1196
Container - 5000	1185	4356	1202
Container - 6000	1554	4815	1461
Container - 7000	1446	4360	1325
Container - 8000	1576	4769	1449
Container - 9000	1498	4551	1383
Container - 10000	1767	2617	887
Cruise	na	na	na
General Cargo	506	1339	655
ITB	89	234	115
Reefer	467	1402	900
RoRo	514	1541	890
Tanker - Aframax	720	990	780
Tanker - Chemical	682	937	739
Tanker - Handysize	504	693	546
Tanker - Panamax	604	830	654
Tanker - Suezmax	702	965	761

Table 3.21: 2011 Auxiliary Boiler Energy Defaults, kW

Vessel Type	Sea	Maneuvering	Hotelling
Auto Carrier	0	250	250
Bulk	0	134	134
Bulk - Self Discharging	0	130	130
Bulk - Heavy Load	0	137	137
Bulk - Wood Chips	0	134	134
Container - 1000	0	263	263
Container - 2000	0	300	300
Container - 3000	0	517	517
Container - 4000	0	554	554
Container - 5000	0	675	675
Container - 6000	0	623	623
Container - 7000	0	479	479
Container - 8000	0	572	572
Container - 9000	0	572	572
Container - 10000	0	572	572
Cruise	0	1549	1549
General Cargo	0	134	134
ITB	0	0	0
Reefer	0	338	338
RoRo	0	275	275
Tanker - Aframax	0	371	2750
Tanker - Chemical	0	371	2750
Tanker - Handysize	0	371	2750
Tanker - Panamax	0	371	2750
Tanker - Suezmax	0	371	3000

Table 3.22: Fuel Correction Factors

Fuel Used	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4
HFO (2.7% S)	1	1	1	1	1	1	1	1	1	1
HFO (1.5% S)	1	1	1	0.555	0.82	0.82	0.82	1	1	1
MGO (0.5% S)	0.94	1	1	0.185	0.25	0.25	0.25	1	0.94	1
MDO (1.5% S)	0.94	1	1	0.555	0.47	0.47	0.47	1	0.94	1
MGO (0.1% S)	0.94	1	1	0.037	0.17	0.17	0.17	1	0.94	1
MGO (0.3% S)	0.94	1	1	0.111	0.21	0.21	0.21	1	0.94	1
MGO (0.4% S)	0.94	1	1	0.148	0.23	0.23	0.23	1	0.94	1
ULSD	0.94	1	1	0.0006	0.15	0.15	0.15	1	0.94	1
LNG	1	1	1	1	1	1	1	1	1	1

LNG fuel correction factors set to 1 as direct emissions factors already account for LNG engines meeting Tier 3 standards

ULSD factors based on scaling from 0.5%S to 0.1%S MGO and further scaling 0.1%S MGO to 0.0015%S

Fuel Consumption Factors	SFOC	Units	Source
Main Engine	195	gHFO/kWh	Implied by CO2 emissions factors, converted using ANL GREET fuel property data
Aux Engine	215	gHFO/kWh	Implied by CO2 emissions factors, converted using ANL GREET fuel property data
Boiler	305	gHFO/kWh	Puget Sound Maritime Emissions Inventory

Ship Emissions and Fuel Consumption Estimates

Inputs

Route Definition

Ship Type	Origin	Destination	Distance at Sea (nm)	Transit Speed (knots)	Transit Time (hours)	Maneuvering Time (hours)	Time at Berth (Origin - hours)	Time at Berth (Destination - hours)	Time within 200 nm: Transit	Time within 200 nm: Manuvering	Time within 200 nm: Hotelling
RoRo	Anchorage	Tacoma	1450	22	65.9	2	10	0	14%	50%	50%

Vessel Details

Service Speed (knots)	Max Speed (knots)	Installed Power (kW)	Main Engine Speed (RPM)	Aux Engine Speed (RPM)	Main Engine Type	Aux Engine Type	Boiler Type
24	25.5	52200	400	720	Medium speed diesel 2000 - 2010	Medium speed diesel 2000 - 2010	Fuel Oil Aux Boiler All

Outputs

Emissions Calcs

Mode	Time	Main Engine Load (kW)	Aux Engine Load (kW)	Aux Boiler Load (kW)	Fuel - In ECA	Fuel - Outside ECA
Transit	65.9	33396	514	0	MGO (0.1% S)	MGO (0.1% S)
Manuvering	2	1044	1541	275	MGO (0.1% S)	MGO (0.1% S)
Hotelling	10	0	890	275	MGO (0.1% S)	MGO (0.1% S)

Emissions Within 200nm (tons per trip)

Mode	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4
Transit	4.15	0.17	0.37	0.14	0.09	0.07	0.09	232	0.01	0.00
Manuvering	0.09	0.01	0.01	0.00	0.00	0.00	0.00	2	0.00	0.00
Hotelling	0.06	0.00	0.01	0.00	0.00	0.00	0.00	5	0.00	0.00
Total Emissions (tons)	4.30	0.19	0.39	0.15	0.09	0.07	0.09	239	0.01	0.00
Emissions Rate (g/kWh)	12.31	0.53	1.13	0.43	0.26	0.21	0.26	684	0.03	0.01
Emissions Rate (g/MMBTU HFOe, HHV)	1568.5	67.7	143.5	54.5	32.7	26.2	32.7	87199	3.7	1.3

Emissions Outside 200nm (tons per trip)

Mode	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4
Transit	25.95	1.06	2.34	0.90	0.54	0.43	0.54	1451	0.06	0.02
Manuvering	0.09	0.01	0.01	0.00	0.00	0.00	0.00	2	0.00	0.00
Hotelling	0.06	0.00	0.01	0.00	0.00	0.00	0.00	5	0.00	0.00
Total Emissions (tons)	26.10	1.08	2.36	0.91	0.54	0.43	0.54	1458	0.06	0.02
Emissions Rate (g/kWh)	12.24	0.51	1.10	0.43	0.25	0.20	0.25	683	0.03	0.01
Emissions Rate (g/MMBTU HFOe, HHV)	1564.9	64.6	141.3	54.5	32.5	26.0	32.5	87390	3.7	1.3

Total Emissions (tons per trip)

Mode	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4
Transit	30.11	1.23	2.71	1.05	0.63	0.50	0.63	1683	0.07	0.02
Manuvering	0.17	0.03	0.03	0.00	0.00	0.00	0.00	4	0.00	0.00
Hotelling	0.13	0.01	0.01	0.01	0.00	0.00	0.00	10	0.00	0.00
Total Emissions (tons)	30.40	1.26	2.75	1.06	0.63	0.51	0.63	1697	0.07	0.02
Emissions Rate (g/kWh)	12.25	0.51	1.11	0.43	0.25	0.20	0.25	683	0.03	0.01
Emissions Rate (g/MMBTU HFOe, HHV)	1565.5	65.0	141.6	54.5	32.5	26.0	32.5	87363	3.7	1.3

Fuel Consumption Estimates

Geographic Region	Main Engine	Aux Engine	Aux Boiler
Fuel Consumed Within 200nm (MT HFOe)	59.4	2.3	0.5
Fuel Consumed Outside 200nm (MT HFOe)	370.2	7.6	0.5
Fuel Consumed (MT HFOe)	429.6	9.9	1.0

Emissions Factors (g/kWh)

Within 200nm

Main Engine	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4
Transit	12.22	0.50	1.10	0.43	0.26	0.20	0.26	683	0.03	0.01
Manuvering	56.58	10.59	10.65	0.43	1.86	1.49	1.86	683	0.03	0.01
Hotelling	56.58	10.59	10.65	0.43	1.86	1.49	1.86	683	0.03	0.01
Aux Engine	**NOx**	**VOC**	**CO**	**SO2**	**PM10**	**PM2.5**	**DPM**	**CO2**	**N2O**	**CH4**
Transit	12.22	0.50	1.10	0.46	0.17	0.14	0.17	683	0.03	0.01
Manuvering	12.22	0.50	1.10	0.46	0.17	0.14	0.17	683	0.03	0.01
Hotelling	12.22	0.50	1.10	0.46	0.17	0.14	0.17	683	0.03	0.01
Aux Boiler	**NOx**	**VOC**	**CO**	**SO2**	**PM10**	**PM2.5**	**DPM**	**CO2**	**N2O**	**CH4**
Transit	1.97	0.10	0.20	0.61	0.14	0.11	0.14	970	0.08	0.00
Manuvering	1.97	0.10	0.20	0.61	0.14	0.11	0.14	970	0.08	0.00
Hotelling	1.97	0.10	0.20	0.61	0.14	0.11	0.14	970	0.08	0.00

Outside 200nm

Main Engine	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4
Transit	12.22	0.50	1.10	0.43	0.26	0.20	0.26	683	0.03	0.01
Manuvering	56.58	10.59	10.65	0.43	1.86	1.49	1.86	683	0.03	0.01
Hotelling	56.58	10.59	10.65	0.43	1.86	1.49	1.86	683	0.03	0.01
Aux Engine	**NOx**	**VOC**	**CO**	**SO2**	**PM10**	**PM2.5**	**DPM**	**CO2**	**N2O**	**CH4**
Transit	12.22	0.50	1.10	0.46	0.17	0.14	0.17	683	0.03	0.01
Manuvering	12.22	0.50	1.10	0.46	0.17	0.14	0.17	683	0.03	0.01
Hotelling	12.22	0.50	1.10	0.46	0.17	0.14	0.17	683	0.03	0.01
Aux Boiler	**NOx**	**VOC**	**CO**	**SO2**	**PM10**	**PM2.5**	**DPM**	**CO2**	**N2O**	**CH4**
Transit	1.97	0.10	0.20	0.61	0.14	0.11	0.14	970	0.08	0.00
Manuvering	1.97	0.10	0.20	0.61	0.14	0.11	0.14	970	0.08	0.00
Hotelling	1.97	0.10	0.20	0.61	0.14	0.11	0.14	970	0.08	0.00

Ship Emissions and Fuel Consumption Estimates

Inputs

Route Definition

Ship Type	Origin	Destination	Distance at Sea (nm)	Transit Speed (knots)	Transit Time (hours)	Maneuvering Time (hours)	Time at Berth (Origin - hours)	Time at Berth (Destination - hours)	Time within 200 nm: Transit	Time within 200 nm: Manuvering	Time within 200 nm: Hotelling
RoRo	Anchorage	Tacoma	1450	22	65.9	2	10	0	14%	50%	50%

Vessel Details

Service Speed (knots)	Max Speed (knots)	Installed Power (kW)	Main Engine Speed (RPM)	Aux Engine Speed (RPM)	Main Engine Type	Aux Engine Type	Boiler Type
24	25.5	52200	400	720	Low Pressure DF LNG All	Low Pressure DF LNG All	LNG Aux Boiler All

Outputs

Emissions Calcs

Mode	Time	Main Engine Load (kW)	Aux Engine Load (kW)	Aux Boiler Load (kW)	Fuel - In ECA	Fuel - Outside ECA
Transit	65.9	33396	514	0	LNG	LNG
Manuvering	2	1044	1541	275	LNG	LNG
Hotelling	10	0	890	275	LNG	LNG

Emissions Within 200nm (tons per trip)

Mode	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4
Transit	0.65	0.00	0.65	0.03	0.01	0.01	0.00	151	0.01	1.80
Manuvering	0.01	0.00	0.02	0.00	0.00	0.00	0.00	1	0.00	0.02
Hotelling	0.01	0.00	0.01	0.00	0.00	0.00	0.00	3	0.00	0.03
Total Emissions (tons)	0.67	0.00	0.68	0.03	0.01	0.01	0.00	156	0.01	1.84
Emissions Rate (g/kWh)	1.92	0.00	1.95	0.10	0.02	0.02	0.00	445	0.03	5.27
Emissions Rate (g/MMBTU HFOe, HHV)	245.1	0.1	247.8	12.3	3.1	3.0	0.0	56717	4.0	671.7

Emissions Outside 200nm (tons per trip)

Mode	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4
Transit	4.04	0.00	4.04	0.21	0.04	0.04	0.00	943	0.07	11.26
Manuvering	0.01	0.00	0.02	0.00	0.00	0.00	0.00	1	0.00	0.02
Hotelling	0.01	0.00	0.01	0.00	0.00	0.00	0.00	3	0.00	0.03
Total Emissions (tons)	4.06	0.00	4.07	0.21	0.04	0.04	0.00	948	0.07	11.30
Emissions Rate (g/kWh)	1.90	0.00	1.91	0.10	0.02	0.02	0.00	444	0.03	5.30
Emissions Rate (g/MMBTU HFOe, HHV)	243.5	0.1	244.0	12.4	2.7	2.6	0.0	56815	4.0	677.3

Total Emissions (tons per trip)

Mode	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4
Transit	4.68	0.00	4.68	0.24	0.05	0.05	0.00	1094	0.08	13.06
Manuvering	0.03	0.00	0.05	0.00	0.00	0.00	0.00	3	0.00	0.03
Hotelling	0.03	0.00	0.02	0.00	0.00	0.00	0.00	6	0.00	0.05
Total Emissions (tons)	4.73	0.00	4.75	0.24	0.05	0.05	0.00	1103	0.08	13.14
Emissions Rate (g/kWh)	1.91	0.00	1.91	0.10	0.02	0.02	0.00	444	0.03	5.29
Emissions Rate (g/MMBTU HFOe, HHV)	243.7	0.1	244.5	12.4	2.7	2.7	0.0	56801	4.0	676.5

Fuel Consumption Estimates

Geographic Region	Main Engine	Aux Engine	Aux Boiler
Fuel Consumed Within 200nm (MT HFOe)	59.4	2.3	0.5
Fuel Consumed Outside 200nm (MT HFOe)	370.2	7.6	0.5
Fuel Consumed (MT HFOe)	429.6	9.9	1.0

Emissions Factors (g/kWh)

Within 200nm

Main Engine	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4
Transit	1.90	0.00	1.90	0.10	0.02	0.02	0.00	444	0.03	5.30
Manuvering	8.80	0.01	18.39	0.10	0.15	0.15	0.00	444	0.03	5.30
Hotelling	8.80	0.01	18.39	0.10	0.15	0.15	0.00	444	0.03	5.30
Aux Engine	**NOx**	**VOC**	**CO**	**SO2**	**PM10**	**PM2.5**	**DPM**	**CO2**	**N2O**	**CH4**
Transit	1.90	0.00	1.90	0.10	0.02	0.02	0.00	444	0.03	5.30
Manuvering	1.90	0.00	1.90	0.10	0.02	0.02	0.00	444	0.03	5.30
Hotelling	1.90	0.00	1.90	0.10	0.02	0.02	0.00	444	0.03	5.30
Aux Boiler	**NOx**	**VOC**	**CO**	**SO2**	**PM10**	**PM2.5**	**DPM**	**CO2**	**N2O**	**CH4**
Transit	2.10	0.10	0.20	0.00	0.80	0.64	0.00	677	0.08	0.00
Manuvering	2.10	0.10	0.20	0.00	0.80	0.64	0.00	677	0.08	0.00
Hotelling	2.10	0.10	0.20	0.00	0.80	0.64	0.00	677	0.08	0.00

Outside 200nm

Main Engine	NOx	VOC	CO	SO2	PM10	PM2.5	DPM	CO2	N2O	CH4
Transit	1.90	0.00	1.90	0.10	0.02	0.02	0.00	444	0.03	5.30
Manuvering	8.80	0.01	18.39	0.10	0.15	0.15	0.00	444	0.03	5.30
Hotelling	8.80	0.01	18.39	0.10	0.15	0.15	0.00	444	0.03	5.30
Aux Engine	**NOx**	**SO2**	**CO**	**SO2**	**PM10**	**PM2.5**	**DPM**	**CO2**	**N2O**	**CH4**
Transit	1.90	0.00	1.90	0.10	0.02	0.02	0.00	444	0.03	5.30
Manuvering	1.90	0.00	1.90	0.10	0.02	0.02	0.00	444	0.03	5.30
Hotelling	1.90	0.00	1.90	0.10	0.02	0.02	0.00	444	0.03	5.30
Aux Boiler	**NOx**	**VOC**	**CO**	**SO2**	**PM10**	**PM2.5**	**DPM**	**CO2**	**N2O**	**CH4**
Transit	2.10	0.10	0.20	0.00	0.80	0.64	0.00	677	0.08	0.00
Manuvering	2.10	0.10	0.20	0.00	0.80	0.64	0.00	677	0.08	0.00
Hotelling	2.10	0.10	0.20	0.00	0.80	0.64	0.00	677	0.08	0.00

ATTACHMENT E

Table B-2
Combusted Gas Characteristics
Puget Sound Energy – Liquefied Natural Gas Project
Tacoma, Washington

Combusted Gas Characteristics
0.799393301

Parameters	Natural Gas[a]	Flared Waste Gas[a]									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 (mg/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 (mg/m	144	144	144	144	144	144	144	144	144	144	
m,p-Xylene Concentration (mg/m^3)	986	986	986	986	986	986	986	986	986	986	
o-Xylene Concentration (mg/m^3)[b]	165	165	165	165	165	165	165	165	165	165	
Toluene Concentration (mg/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.

Fugitive Emissions from Equipment Leaks

EQUIPMENT INFORMATION

Component	Phase	Fluid Serviced									Emission Factors[3] (lb/hr per component)	LDAR Control Efficiency[4]
		Amine Gas	Boil-Off Gas	Ethylene	Fuel Gas	Hydrocarbon Liquid	Liquefied Natural Gas	Mixed Refrigerant	Natural Gas	Untreated Natural Gas		
Valves	Gas/Vapor	39	9	12	36			112	185	30	0.00137	75%
	Light Liquid					33	244				0.00537	75%
	Heavy Liquid										0.000502	0%
Pump Seals	Light Liquid					1					0.0493	75%
	Heavy Liquid										0.00982	0%
Flanges/Connectors	Gas/Vapor	0	7	2	15			28	77	15	0.000559	30%
	Light Liquid					6	114				0.000559	30%
	Heavy Liquid										0.000559	30%
Compressor Seals	Gas/Vapor	0	2	0	0	0	0	1	1	0	0.0166	75%
Relief Valves	Gas/Vapor	3	0	1	3	1	19	8	9	2	0.0220	75%
Swivel Joints	Light Liquid						4				0.0493	75%

FLUID HAP/TAP CONTENT

Pollutant	CAS / ID	Fluid								
		Amine Gas	Boil-Off Gas	Ethylene	Fuel Gas	Hydrocarbon Liquid	Liquefied Natural Gas	Mixed Refrigerant	Natural Gas	Untreated Natural Gas
Methane Content (%wt)[1]	74-82-8	100%	100%	100%	100%	100%	100%	100%	100%	100%
n-Hexane (ppmw)[1]	110-54-3	70	5.7E-10	0	1,185	210,669	27	0	1,185	1,185
Hydrogen sulfide (ppmw)[1]	2148878	3,128	0.00035	0	22	0.010	0.21	0	22	166
Benzene (ppmw)[b, 2]	71-43-2	4.0	4.0	0	4.0	4.0	4.0	0	4.0	4.0
Ethylbenzene (ppmw)[b, 2]	100-41-4	0.20	0.20	0	0.20	0.20	0.20	0	0.20	0.20
m,p-Xylene (ppmw)[b, 2]	106-42-3	1.3	1.3	0	1.3	1.3	1.3	0	1.3	1.3
o-Xylene (ppmw)[b, 2]	95-47-6	0.22	0.22	0	0.22	0.22	0.22	0	0.22	0.22
Toluene (ppmw)[b, 2]	108-88-3	3.5	3.5	0	3.5	3.5	3.5	0	3.5	3.5

POTENTIAL EMISSIONS

Pollutant	CAS / ID	Amine Gas	Boil-Off Gas	Ethylene	Fuel Gas	Hydrocarbon Liquid	Liquefied Natural Gas	Mixed Refrigerant	Natural Gas	Untreated Natural Gas	Total
Hourly Emissions[a] (lb/hr)											
Methane[6]	74-82-8	0.03	0.01	0.01	0.03	0.06	0.53	0.10	0.15	0.03	**0.95**
n-Hexane	110-54-3	2.1E-06	8.1E-18	0	4.1E-05	0.014	1.4E-05	0	1.7E-04	3.2E-05	**0.014**
Hydrogen sulfide	2148878	9.3E-05	4.9E-12	0	7.5E-07	6.61E-10	1.1E-07	0	3.2E-06	4.5E-06	**1.0E-04**
Benzene	71-43-2	1.2E-07	5.7E-08	0	1.4E-07	2.6E-07	2.1E-06	0	5.9E-07	1.1E-07	**3.4E-06**
Ethylbenzene	100-41-4	5.8E-09	2.7E-09	0	6.8E-09	1.3E-08	1.0E-07	0	2.9E-08	5.3E-09	**1.6E-07**
m,p-Xylene	106-42-3	4.0E-08	1.9E-08	0	4.6E-08	8.6E-08	7.0E-07	0	2.0E-07	3.6E-08	**1.1E-06**
o-Xylene	95-47-6	6.7E-09	3.2E-09	0	7.8E-09	1.4E-08	1.2E-07	0	3.3E-08	6.1E-09	**1.9E-07**
Toluene	108-88-3	1.0E-07	4.9E-08	0	1.2E-07	2.2E-07	1.8E-06	0	5.1E-07	9.5E-08	**2.9E-06**
Total HAPs	HAP	2.8E-07	1.3E-07	0	3.2E-07	6.0E-07	4.9E-06	0	1.4E-06	2.5E-07	**7.8E-06**
Daily Emissions[a] (kg / day)											
Methane[6]	74-82-8	0.33	0.15	0.11	0.38	0.70	5.73	1.06	1.60	0.30	**10.36**
n-Hexane	110-54-3	2.26E-05	8.77E-17	0.00E+00	4.48E-04	1.48E-01	1.57E-04	0.00E+00	1.90E-03	3.50E-04	**1.51E-01**
Hydrogen sulfide	2148878	1.02E-03	5.34E-11	0.00E+00	8.19E-06	7.19E-09	1.21E-06	0.00E+00	3.47E-05	4.91E-05	**1.11E-03**
Benzene	71-43-2	1.31E-06	6.19E-07	0.00E+00	1.53E-06	2.83E-06	2.31E-05	0.00E+00	6.47E-06	1.19E-06	**3.71E-05**
Ethylbenzene	100-41-4	6.34E-08	2.99E-08	0.00E+00	7.37E-08	1.37E-07	1.12E-06	0.00E+00	3.13E-07	5.77E-08	**1.79E-06**
m,p-Xylene	106-42-3	4.34E-07	2.05E-07	0.00E+00	5.05E-07	9.38E-07	7.65E-06	0.00E+00	2.14E-06	3.95E-07	**1.23E-05**
o-Xylene	95-47-6	7.27E-08	3.43E-08	0.00E+00	8.45E-08	1.57E-07	1.28E-06	0.00E+00	3.58E-07	6.61E-08	**2.05E-06**
Toluene	108-88-3	1.13E-06	5.34E-07	0.00E+00	1.32E-06	2.44E-06	1.99E-05	0.00E+00	5.58E-06	1.03E-06	**3.20E-05**
Total HAPs	HAP	3.02E-06	1.42E-06	0.00E+00	3.50E-06	6.51E-06	5.31E-05	0.00E+00	1.49E-05	2.74E-06	**8.52E-05**

Annual Emissions[a] (short ton per year)											
Methane[6]	74-82-8	0.13	0.06	0.05	0.15	0.28	2.30	0.43	0.64	0.12	**4.2**
n-Hexane	110-54-3	9.1E-06	3.5E-17	0	0.00018	0.060	6.3E-05	0	0.00076	0.00014	**0.061**
Hydrogen sulfide	2148878	0.00041	2.1E-11	0	3.3E-06	2.9E-09	4.9E-07	0	1.4E-05	2.0E-05	**4.5E-04**
Benzene	71-43-2	5.3E-07	2.5E-07	0	6.1E-07	1.1E-06	9.3E-06	0	2.6E-06	4.8E-07	**1.5E-05**
Ethylbenzene	100-41-4	2.6E-08	1.2E-08	0	3.0E-08	5.5E-08	4.5E-07	0	1.3E-07	2.3E-08	**7.2E-07**
m,p-Xylene	106-42-3	1.7E-07	8.2E-08	0	2.0E-07	3.8E-07	3.1E-06	0	8.6E-07	1.6E-07	**4.9E-06**
o-Xylene	95-47-6	2.9E-08	1.4E-08	0	3.4E-08	6.3E-08	5.2E-07	0	1.4E-07	2.7E-08	**8.3E-07**
Toluene	108-88-3	4.6E-07	2.1E-07	0	5.3E-07	9.8E-07	8.0E-06	0	2.2E-06	4.1E-07	**1.3E-05**
Total HAPs	HAP	1.2E-06	5.7E-07	0	1.4E-06	2.6E-06	2.1E-05	0	6.0E-06	1.1E-06	**3.4E-05**

Calculations:

[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

[b] Pollutant Concentration (ppmw) = [Pollutant Concentration ($\mu g/m^3$)] / [453.6 g/lb] / [10^6 $\mu g/g$] / [35.31 ft^3/m^3] / [Gas Density (lb/cf)] x 10^6

Benzene Concentration ($\mu g/m^3$) =	2,980	[5]
Ethylbenzene Concentration ($\mu g/m^3$) =	144	[5]
m,p-Xylene Concentration ($\mu g/m^3$) =	986	[5]
o-Xylene Concentration ($\mu g/m^3$) =	165	[5]
Toluene Concentration ($\mu g/m^3$) =	2,570	[5]
Natural Gas Density (lb/scf) =	0.046	[5]

Notes:

[1] Provided by CB&I.

[2] From "Natural Gas Analysis"; Environmental Partners, Inc.; February 3, 2014. Most HAPs will go through with the heavy hydrocarbons, but the fraction is unknown. Therefore, we assume each fluid has the full concentration of HAP to provide a conservative emissions estimate.

[3] Terminal/Depot factors from South Coast Air Quality Management District's "Guidelines for Fugitive Emissions Calculations" (June 2003). In this guidance, the District updated emissions factors that were identified in the EPA's "Protocol for Equipment Leak Emission Estimates (November 1995).

[4] Control effectiveness from Texas Commission for Environmental Quality (TCEQ) "Control Efficiencies for TCEQ Leak Detection and Repair Programs" (July 2011) for its 28M fugitive leak detection program.

[5] See fuel characteristics in Table B-2.

[6] Assume all VOC is CH_4.

ATTACHMENT F

Project Greenhouse Gases Emissions Summary

Source	CO_2 Emission Factor (lb/MMBtu)	CO_2 Emission Rate (MT/yr)	CH_4[1] Emission Rate (lb/MMBtu)	CH_4[1] Emission Rate (MT/yr)	N_2O Emission Factor (lb/MMBtu)	N_2O Emission Rate[a] (MT/yr)	Total CO_2 Equivalent[b] (MT/yr)
Flare	--	27,110[2]		40[2]	0.0002	0.033	28,131
Vaporizer	117	841		0.036	0.0002	0.0016	842
WPG	117.0	4183	0.002	0.0788	0.0002	0.0079	4,186
Regen	117.0	744	0.002	0.0140	0.0002	0.0014	744
Diesel Generator[6]	163.1	534	0.007	0.030	0.0013	0.006	536
Fugitives	--	--	3.8		--	--	95
Total	--	33,411	4	40.6	--	0.050	34,533

Calculations:

[a] Annual Emissions (tons/yr) = [Maximum Heat Input (MMBtu/yr)] x [Emission Factor (lb/MMBtu)] / [2,000 lbs/ton] x [0.907185 MT/ton]

	Vaporizer[3] (MMBtu/yr)	Flare[3, 4] (MMBtu/yr)	WPG (MMBtu/yr)	Regen (MMBtu/yr)	Diesel (gal/hr)
Heat Input (MMBtu/yr) =	15,840	326,707	78,840	14,016	104.6

[b] Total CO_2 Equivalent Emissions = [CO_2 Emissions] + [CH_4 Emissions x CH_4 Global Warming Potential] + [N_2O Emissions x N_2O Global Warming Potential]

CH_4 Global Warming Potential = 25 [5]

N_2O Global Warming Potential = 298 [5]

Notes:

[1] Assume all VOC is CH_4.

[2] Based on maximum of liquefying cases plus maximum of LNG transfer cases calculated in Table 2 for CO_2 emissions from the flare.

[3] NOC Application Supplement dated September 9, 2017; Attachment A, Table 1.

[4] Maximum of liquefying cases plus maximum of LNG transfer cases on an annual basis.

[5] 40 CFR 98 (revised November 29, 2013).

[5] Diesel generator maximum 500 hours per year, fuel consumption at 100% power rating = 147.3 gallon per hour

Table 2. CO_2 Emissions from Flare

Flare Waste Gas Case[1]	CO_2 in Exhaust (scfm)	CO_2 in Exhaust (lb/hr)[a]
Liquefying Case 1	552	3,722
Liquefying Case 2	90	607
Liquefying Case 3	702	4,733
Liquefying Case 4	1,010	6,810
Liquefying Case 5	728	4,908
Holding	16	108
LNG Transfer A1	69	465
LNG Transfer A2/A3	35	236
LNG Transfer B	15	101

Calculations:

[a] CO_2 in Exhaust (lb/hr) = [CO_2 in Exhaust (scfm)] x [28.4 L/cf] x [1 mole/24.5 L] x [44.01 g/mole] / [454 g/lb] x [60 min/hr]

Notes:

[1] Provided by CB&I and flare vendor.

Emission Unit Inventory and Rates

Equipment	Rate[a]		Hours of Operation[a]	Fuel
Vaporizer	66	MMBtu/hr	240	Natural Gas
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		
Emergency Cryogenic BOG Typical				
Waste Gas Flow	45,833	scf/hr	50	Waste Gas
Waste Gas Heat Input	36.3	MMBtu/hr		
Emergency Cryogenic BOG Highest				
Waste Gas Flow	45,833	scf/hr	50	Waste Gas
Waste Gas Heat Input	50.6	MMBtu/hr		
Pilots	10	scf/min	8,760	Natural Gas
Fugitives	--		8,760	--
Truck Loading	4,563	trucks/yr	1,267	
WPG Pretreatment Heater	9	MMBtu/hr	8,760	Natural Gas
Regen Pretreatment Heater	1.6	MMBtu/hr	8,760	Natural Gas
Emergency Generator	1,500	kW	100	Diesel

Notes:

[a] Provided by CB&I.

Project Emissions Summary

Pollutant	Vaporizer		Enclosed Ground Flare (Worst-Case Gas)		Fugitives	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Criteria Pollutants						
$PM/PM_{10}/PM_{2.5}$	0.46	0.055	0.28	1.2	0	0
Sulfur dioxide (SO_2)	0.14	0.017	2.1	9.1	0	0
Nitrogen oxides (NO_X)	0.72	0.086	0.86	3.7	0	0
Carbon monoxide (CO)	2.4	0.29	2.7	12	0	0
VOCs	0.33	0.040	10	45	1.0	4.2
Lead	3.0E-05	3.6E-06	1.8E-05	8.0E-05	0	0
Total HAPs	0.31	0.037	1.5	3.2	7.8E-06	3.4E-05