2019 Greenhouse Inventory

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Prepared by: Puget Sound Energy

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EXECUTIVE SUMMARY

Puget Sound Energy's (PSE) operating rates and greenhouse gas (GHG) emissions for calendar year 2019 are summarized in Table ES-1, Table ES-2, and Table ES-3. The emission percentages indicated in Table ES-2 are the percentage of the total emissions of the particular pollutant within each scope. The emission percentages indicated in Table ES-3 are the percentage of the total emissions of the particular pollutant among all sources.

A majority of the carbon dioxide (CO2) emissions were from generated and purchased electricity (63.6%), while the remaining emissions were from natural gas supply to end-users (36.4%). For methane (CH4), the majority of emissions were fugitive from natural gas operations (80.4%). Generated and purchased electricity also accounted for all nitrous oxide (N2O) emissions and all sulfur hexafluoride (SF6) emissions.

Compared to 2018, total electricity delivered to customers in 2019 decreased by 3.8 percent, and total emissions increased 6.4 percent[1]. This trend is largely due to an increase in natural gas generation owned by PSE, an increase in energy deliveries from Centralia, and a decrease in firm and spot market purchases.

The "direct use" of natural gas often includes heating for water, buildings, and industrial processes, as well as use as a raw material to produce petrochemicals, plastics, paints, and a wide variety of other products. The emissions associated with the "direct use" of natural gas by end-users together with the emissions associated with power generation and power deliveries from natural gas combustion (direct and indirect) are accounted for in this inventory.

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[1] Per WUTC methodology, subject to revision

1.0 INTRODUCTION

This document presents an inventory of greenhouse gas (GHG) emissions from Puget Sound Energy (PSE) operations during the calendar year 2019. PSE's primary business is electric generation, purchase, distribution, and sales and natural gas purchase, distribution, and sales. This inventory accounts for the four major GHGs most relevant to PSE's businesses. They are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6). GHG emissions were calculated in accordance with a standardized nationally accepted protocol.

1.1 Purpose

This inventory is intended to provide PSE with the information to achieve five major goals:

- Maintaining an accurate and transparent estimate of GHG emissions;
- Analyzing PSE's GHG emission sources in relation to size and impact;
- Tracking PSE's GHG emissions over time;
- Evaluating PSE's GHG emissions from electric production and purchase relative to those of other electric generators and electric utilities; and
- Estimating the emissions avoided through PSE's conservation programs.

1.2 Inventory Organization

This inventory is organized into 9 sections. The introduction explains the purpose and organization of this inventory. The background of PSE's GHG inventory is described in Section 2.0. Major accounting issues within PSE's GHG inventory are discussed in Section 3.0. Section 4.0 presents the choice of organizational and operational boundaries used in the inventory. Section 5.0 documents the calculation methodology, data sources, and assumptions made to estimate PSE's GHG emissions. Section 6.0 provides a list of tables used to present and analyze PSE's GHG emissions during calendar year 2019. Section 7.0 provides an evaluation of the sources of PSE's GHG emissions and discusses potential uncertainties in the inventory. Section 8.0 describes changes in PSE's GHG inventory over time. Section 9.0 presents PSE's conservation programs that are relevant to the inventory and the estimated amount of GHG emissions avoided as a result of these conservation programs. The last section contains a list of references used to compile this inventory.

2.0 BACKGROUND

From 2002 to 2010, PSE's GHG inventories have followed a widely-accepted international GHG accounting protocol, the Greenhouse Gas Protocol (WRI/WBCSD 2004). The Greenhouse Gas Protocol (GHG Protocol) was developed by a consortium of businesses, business organizations, governments, and non-governmental organizations led jointly by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD).

The WRI/WBCSD GHG Protocol has set the standard for development of GHG accounting methods for many industries and state GHG programs. Under the GHG Protocol, six groups of GHGs are tracked: CO_2, CH_4, N_2O, SF_6, hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs). Two of the groups of gases, HFCs and PFCs, are not tracked quantitatively in this inventory because PSE's emissions of these GHGs are negligible.

2.1 Regulatory Actions

This inventory continues to incorporate many of the standards developed by the WRI/WBSCD. However, regulatory actions taken at the federal and state levels now require PSE to disclose its emissions using newly-set procedures. Where mandatory, PSE has integrated these standards into this report.

On September 22, 2009, the United States Environmental Protection Agency (EPA) signed the Greenhouse Gas Mandatory Reporting Rule (GHG MRR) (EPA 2009). The rule requires reporting of GHG emissions under EPA's GHG Reporting Program from large sources and suppliers in the United States and is intended to collect accurate and timely emissions data to inform future policy decisions. The final rule was published in the Federal Register on October 30, 2009, and became effective on December 29, 2009. Under the rule, suppliers of fossil fuels or industrial GHGs, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more of carbon dioxide equivalent (CO_2e) per calendar year are required to submit annual reports to the EPA. PSE is subject to the reporting requirements in Subparts A, C, D, W, DD, and NN in the GHG MRR. Under these requirements, PSE must calculate GHG emissions from fuel combustion and electrical transmission and distribution (T-D) equipment for electric operations, natural gas system operations, and combustion of natural gas supplied to certain customers. The reporting timeline varies for different subparts of the GHG MRR. The initial reporting year for Subparts A, C, D, and NN was 2010, while the reporting year for Subparts W and DD was 2011.

In December 2014, the EPA promulgated a final rule under Subpart A (effective January 1, 2015) that adds chemical-specific and default global warming potentials (GWPs) for a number of fluorinated GHGs and fluorinated heat transfer fluids to the general provisions of the GHG MRR. The rule amendment increases the completeness and accuracy of the CO_2e emissions calculated and reported by suppliers and emitters of fluorinated GHGs and heat transfer fluids. The only fluorinated GHG applicable for reporting by PSE is SF_6. The GWP for SF_6 remains unchanged, so the rule amendment does not affect PSE's GHG emission calculations and reporting.

In November 2014, the EPA promulgated a final rule under Subpart W (effective January 1, 2015) that revises the calculation methodology, monitoring, and data reporting requirements for natural gas operations applicable to PSE's GHG inventory. The changes are implemented in this GHG inventory.

In March 2010, the Washington State Legislature passed new legislation, Substitute Senate Bill 6373, amending the 2008 statute (House Bill 2815) requiring the Washington State Department of Ecology (Ecology) to establish rules for the mandatory reporting of GHG emissions. The amended legislation emphasizes consistency with the EPA's reporting program, which was finalized after the passage of the 2008 statute. Ecology then restarted its rulemaking process to align the state and federal programs. Under the Washington State GHG reporting requirements, as prescribed in Washington Administrative Code (WAC) 173-441, facilities and transportation fuel suppliers that emit 10,000 metric tons or more per year of GHG emissions in Washington are required to report GHG emissions. Reporting started with 2012 emissions, which were to be reported in 2013.

The EPA has made multiple amendments to the GHG Reporting Program since its adoption in 2009. Under the Revised Code of Washington (RCW) 70.94.151, Ecology is required to update Chapter 173-441 WAC to maintain consistency with the EPA's Greenhouse Gas Reporting Program. For this reporting period, Ecology last updated Chapter 173-441 WAC October 28, 2016. No updates were found to be applicable.

2.2 Inventory and GHG Reporting Compliance

This inventory is intended to meet the compliance requirements set forth in the federal and state GHG reporting requirements. After the promulgation of the GHG MRR on October 30, 2009, PSE started incorporating GHG MRR calculation methodologies in the 2009 GHG inventory, with the objective of preparing to meet compliance requirements starting in the 2010 reporting year. The GHG MRR, however, has evolved since its first promulgation in 2009. Therefore, new calculation methodologies continue to be added to the GHG inventory to achieve alignment with the new GHG MRR requirements. Since 2011, CO_2, CH_4, N_2O, and SF_6 emissions are quantified using methodologies established in Subparts A, C, D, W, DD, and NN.

Facilities report GHG emissions based on the EPA's GHG MRR. The GHG emissions required to be reported to Ecology use the same calculation methodology as the EPA's GHG MRR. The difference in the reporting requirement is that Washington State has a lower reporting threshold of 10,000 metric tons of CO_2e per calendar year. As such, PSE's GHG inventory continues to enable PSE to comply with local, state, and federal reporting requirements to manage its GHG emissions and to better adapt to future emission reduction programs as they are adopted.

3.0 MAJOR ACCOUNTING ISSUES

To stay relevant with the WRI/WBCSD GHG Protocol, PSE adheres to five principles. The five principles, along with the means by which this report adheres to the principles, are as follows.

- Relevance. Ensure the GHG inventory appropriately reflects the GHG emissions of the company and serves the decision-making needs of users—both internal and external. The intended uses of this inventory are discussed in Section 1.1.
- Completeness. Account for and report on all GHG emission sources and activities within the chosen inventory boundary. Disclose and justify any specific exclusions. The organizational and operational boundaries chosen by PSE are discussed in Section 4.0. Emission sources that are not included in this inventory are presented in Section 7.2.1.
- Consistency. Use consistent methodologies to allow for meaningful comparisons of emissions over time. Transparently document any changes to the data, inventory boundary, methods, or any other relevant factors in the time series. PSE has compiled an annual GHG inventory since 2002. PSE has remained, to the best of its ability, consistent in its emission calculation methodology to allow for meaningful comparisons of emissions over time. However, small changes in the emission calculation methodology have been made over the years due to the changes in data availability. The intention of making these small changes is to increase overall accuracy of the inventory. The differences in data sources and methodologies are presented in Section 8.3.
- Transparency. Address all relevant issues in a factual and coherent manner, based on a clear audit trail. Disclose any relevant assumptions and make appropriate references to the accounting and calculation methodologies and data sources used. Calculation methodologies, sources of data, and assumptions are documented by emission scope in Section 5.0. The references used are listed in Section 10.0 of this inventory.
- Accuracy. Take appropriate measures to ensure that the quantification of GHG emissions is neither over nor under actual emissions, as far as can be judged, and that uncertainties are reduced as far as practicable. Achieve sufficient accuracy utilizing recognized standards to enable users to make decisions with reasonable assurance as to the integrity of the reported information. PSE has endeavored to obtain the best available information from PSE and other relevant organizations. Additionally, efforts were made to minimize error to the greatest extent practicable by utilizing appropriate professional judgment, reputable sources, best available information, and peer review. The integrity of the inventory is further discussed in Section 7.2.

4.0 BOUNDARIES AND SOURCES

Organizational and operational boundaries to define and allocate GHG emissions were chosen for the inventory in accordance with the GHG Protocol. The organizational boundary is used to determine the GHG emissions and sources associated with PSE's activities. The operational boundary further defines these emission sources into "scopes" so that total emissions are accounted for, but double counting is avoided.

4.1 Organizational Boundaries

PSE's organizational boundaries are determined using the equity share approach, i.e., PSE accounts for GHG emissions from its operations according to its share of ownership (operations or assets) in the operation. These operations and assets are detailed in the Puget Energy (PSE's parent company) Annual Report (Form 10-K). The information presented in this document was extracted from the Annual Report and supplemented by additional information provided by relevant PSE personnel.

4.1.1 Electrical Operations

In 2019, PSE supplied electricity to 1,157,496 customers in Western Washington. PSE wholly owns three dual-fuel combustion turbine generation facilities (Frederickson, Fredonia, and Whitehorn), five natural gas combined cycle generation facilities (Encogen, Goldendale, Mint Farm, Ferndale, and Sumas), one internal diesel combustion generation facility (Crystal Mountain), four hydroelectric generation facilities (Electron, Lower Baker River, Upper Baker River, and Snoqualmie Falls), and three wind power generation facilities (Hopkins Ridge, Lower Snake River, and Wild Horse). Also, PSE partially owns one coal-combustion generation facility (Colstrip) and one natural gas combined cycle generation facility (Frederickson Unit 1). All of the generation facilities are located in Western Washington, except for the coal-combustion generation facility (Colstrip), three wind power generation facilities (Hopkins Ridge, Lower Snake River, and Wild Horse), and one natural gas combined cycle generation facility (Goldendale). The coal-combustion generation facility is located in Montana; the three wind power and one natural gas combined cycle generation facilities are located in Eastern Washington.

PSE's total electricity supplied to its customers includes electricity generated by PSE-owned generation facilities and electricity purchased through firm contracts with other electric producers and non-firm contracts on the wholesale electric market. In 2019, 62.8% of electricity delivered to PSE customers was generated by the company, while 30.1% of electricity was purchased via firm contracts and 7.1% from non-firm contracts (Figure 1). The distribution of electricity to PSE's customers is largely provided by PSE-owned lines, while some is transmitted by the Bonneville Power Agency under contract with PSE.

4.1.2 Natural Gas Operations

In 2019, PSE supplied natural gas to 841,427 customers in Western Washington. PSE purchases natural gas from natural gas producers in the United States and Canada. PSE's natural gas supply is transported through pipelines owned by Northwest Pipeline GP (NWP), Gas Transmission Northwest (GTN), Nova Gas Transmission (NOVA), Foothills Pipe Lines (Foothills), and Westcoast Energy (Westcoast). PSE owns its gas distribution networks within its service territory. PSE holds storage capacity in the Jackson

Prairie and Clay Basin underground natural gas storage facilities in the United States and at AECO in Alberta, Canada. One-third of the Jackson Prairie facility is owned by PSE.

4.2 Operational Boundaries

PSE's GHG emissions are categorized into three scopes defined by PSE control or ownership and the operational boundary specifications in the GHG Protocol. Under the GHG Protocol, accounting and reporting of Scope I and Scope II emissions is considered mandatory, while that of Scope III emissions is considered optional.

Scope I emissions are direct GHG emissions released directly by PSE from the operations of PSE-owned facilities. These emissions include those from PSE-owned electric and natural gas operations. Scope II emissions are indirect GHG emissions from the generation of purchased electricity consumed by PSE. Scope III emissions are other indirect GHG emissions resulting from activities by PSE but which occurred at sources not owned or controlled by PSE. These emissions include those from electricity purchased by PSE and resold to another intermediary owner, such as another utility, or to end-users. Also, they include emissions that would result from the complete combustion or oxidation of natural gas provided to end-users on PSE's distribution system.

In addition, emission data for CO_2 emissions from biomass fuels are accounted for and reported separately from the three scopes defined above. This is consistent with the GHG Protocol. The GHG Protocol specifies that these emissions should be accounted for separately because of the relatively quick interplay between biomass fuels and the terrestrial carbon stock. In contrast to biomass fuels, fossil fuels take a much longer time to develop, so the interaction between atmospheric carbon and fossil fuels is not considered in national GHG inventories.

Table 1 summarizes GHG emissions from each area of PSE's operations accounted for in this inventory and identifies the scope under which each area falls.

4.2.1 Scope I (Direct Emissions)

PSE's Scope I emissions come from electric operations and natural gas operations. Consistent with the previous years' GHG inventory, SF_6 emissions from electrical T-D equipment are included. PSE's CH_4 emissions from natural gas storage is below the de minimis level of 2% that is recognized by the GHG Protocol, therefore, were excluded from Scope I emissions. PSE's electric and natural gas profile did not change in 2019. The inclusion and exclusion of these emissions enable PSE's GHG inventory to be consistent with the GHG MRR requirements. Specifically, these emissions are reported under Subpart DD and Subpart W of the GHG MRR.

4.2.1.1 Electric Operations

Within PSE's electric operations, Scope I emissions come from electricity generation, transmission, and distribution systems. The emissions that result from PSE-owned generating facilities are fully accounted for in this inventory. In addition, three potential sources are identified for emissions from electric T-D systems:

- Emissions from electricity generated by PSE and lost in T-D. These emissions are included in the total emissions from electricity generated by PSE, prior to any losses, and were not accounted for separately.
- Emissions from electrical T-D equipment. These emissions include SF_6 emissions from gas-insulated substations, circuit breakers, closed-pressure and hermetically sealed-pressure switchgear, gas-insulated lines containing SF_6, pressurized cylinders, gas carts, electric power transformers, and other containers of SF_6. On December 1, 2010, the EPA finalized the GHG MRR Subpart DD to require calculation and reporting of these emissions. Therefore, the GHG inventory has included SF_6 emissions since 2011 to be consistent with the GHG MRR requirements. SF_6 emissions are very minor when compared to the total GHG emissions footprint.
- Emissions from equipment and materials used for construction, operation, and maintenance of PSE's electric system. This category includes incidental loss of HFCs and PFCs from refrigeration equipment and from incidental leaks of CH_4 at gas-fired turbines. Data regarding the use of PFCs and HFCs in refrigeration equipment and incidental leaks of CH_4 from gas-fired turbines were not available and these were not considered in this inventory. PFCs and HFCs emissions from refrigeration equipment and CH_4 from incidental leaks at gas-fired turbines are extremely minor in relation to the emissions from the coal-combustion generation facilities.

4.2.1.2 Natural Gas Operations

Scope I emissions from natural gas operations come from PSE's natural gas distribution system. These emissions include CO_2 and CH_4 emissions from equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open-ended lines from metering and regulating (M&R) and T-D transfer stations. On November 30, 2010, the EPA finalized the GHG MRR Subpart W to require calculation and reporting of these emissions. Therefore, the GHG inventory has included these emissions since 2011 to be consistent with the GHG MRR requirements. CH_4 emissions account for the majority of PSE's Scope I emissions from natural gas operations.

4.2.1.3 Other Scope I Emissions

Scope I emissions also come from PSE's vehicle fleet, which is used to service PSE's electric and natural gas operations. PSE's vehicle fleet emissions include emissions from combustion of fuel burned by these vehicles as well as any PFCs and/or HFCs released from air conditioning equipment installed in these vehicles. These are all Scope I emissions attributable to PSE. PFCs and/or HFCs are of relatively minor quantities compared to PSE's total GHG emissions. Therefore, they are not quantified in PSE's GHG inventory.

The emissions from the combustion of fuel burned by these vehicles were not calculated for two reasons. First, historically, these emissions have totaled approximately 0.1% of PSE's total emissions output, which is below the de minimis level of 2% that is recognized by the GHG Protocol. Second, the GHG MRR will account for emissions from the transportation sector further up the production stream with a method that is more accurate than the approach recommended by the GHG Protocol. Therefore, these emissions are not included in PSE's GHG inventory to ensure accurate and consistent reporting and to avoid double counting.

4.2.2 Scope II (Indirect Emissions from Electric Power)

PSE's Scope II emissions include emissions from electricity purchased from a third party and used by PSE. PSE accounts for its internal use and system losses of electricity, but it does not differentiate between losses associated with electricity generated by PSE and electricity purchased by PSE from a third party. As such, it is difficult to separate Scope II emissions from total emissions associated with PSE's use of electricity. However, this inventory does account for Scope II emissions. Since PSE's Scope I emissions from electricity generated by PSE are based on the total amount of electricity generated, and PSE's Scope III emissions from purchased electricity sold to others are based on the total electricity purchased, prior to any system loss or PSE use, complete accounting of Scope II emissions is included in Scope I and Scope III emissions.

4.2.3 Scope III (Other Indirect Emissions)

PSE's Scope III emissions are included in the inventory to avoid double counting of emissions among different companies, as these emissions are accounted for as Scope I emissions by the third-party companies. PSE's Scope III emissions include emissions from operations and companies that support or supply PSE, but are not owned or controlled by PSE.

PSE's Scope III emissions accounted for in this inventory are associated with electric operations and certain natural gas operations. Upstream emissions from the generation of power and production of natural gas are also considered part of PSE's Scope III emissions. However, as these emissions are thought to be minor, more uncertain, and further from PSE's control, they were not accounted for in this inventory.

4.2.3.1 Electric Operations

A majority of PSE's Scope III emissions come from third-party generated electricity purchased by PSE and resold to intermediary owners or end-users. The electricity is purchased via firm and non-firm contracts. The purchases and sales are tracked and the data were used to account for PSE's Scope III emissions.

4.2.3.2 Natural Gas Supply

PSE's Scope III emissions associated with natural gas supply includes CO_2 emissions that would result from the complete use of natural gas provided to end-users on their distribution systems. End-users refer to customers that consume no more than 460,000 thousand standard cubic feet (Mscf) of natural gas at a single facility per year.

4.2.3.3 Other Scope III Emissions

Upstream emissions from the generation of power and production of natural gas are attributable to PSE's Scope III emissions. However, as these emissions are thought to be minor, more uncertain, and further from PSE's control, they are not accounted for in this inventory.

Other PSE Scope III emissions may include those associated with employee travel in vehicles other than company vehicles, or emissions associated with wastes. However, as detailed information regarding these emissions are not available and these emissions are thought to be minor in relation to the overall GHG inventory, they were not accounted for in this inventory.

5.0 METHODOLOGY

This inventory was compiled using data provided by PSE, calculation methodologies from WRI/WBCSD sources, the GHG MRR, and other accepted air emission calculation references. The data sources and calculation methodologies are discussed in the following sections by emission scope (Scope I, Scope II, Scope III, and outside scope).

5.1 Scope I

5.1.1 Electric Operations

PSE's Scope I emissions from electric operations were calculated using the GHG MRR Subpart C Tier 2 and Tier 4 calculation methodologies (Table A-1 and Table A-2). These emissions were calculated based on the amount of fuel consumed by the electricity generation facilities. PSE's Scope I emissions from electrical T-D equipment were calculated using the GHG MRR Subpart DD calculation methodologies (Table B-9). These emissions were calculated based on the amount of SF_6 removed from inventory and acquired, less the amount disbursed and used in the electrical T-D equipment.

5.1.2 Natural Gas Operations

PSE's Scope I emissions from its natural gas distribution system were calculated using the GHG MRR Subpart W calculation methodologies (Table B-8). These emissions were calculated based on the number of leaking equipment identified from PSE's leak survey, M&R stations, and default emission factors.

5.1.3 Other Scope I Emissions

No Other Scope I emissions were quantified.

5.2 Scope II (Indirect Emissions Associated With the Purchase of Electricity)

PSE's Scope II emissions were not calculated separately as they could not be separated from Scope I and Scope III emissions, as discussed in Section 4.2.2.

5.3 Scope III (Other Indirect Emissions) Electric Operations

5.3.1 Electric Operations

PSE's Scope III emissions from firm contract purchased electricity were calculated using the amount of electricity purchased, broken down by the electricity generation technology (e.g., coal, natural gas, or petroleum), and emission factors applicable to each generation source. The sources of the emission factors used include the Updated State-level Greenhouse Gas Emission Coefficients for Electricity Generation 1998-2000 (DOE/EIA 2002), Voluntary Reporting of Greenhouse Gases Program – Fuel and Energy Source Codes and Emission Coefficients (DOE/EIA 2011), Carbon Dioxide Emissions from the Generation of Electric Power in the United States (DOE/EPA 2000), AP-42 emission factors (EPA), and EPA eGRID regional average emission factors (Table A-3).

PSE's Scope III emissions from non-firm contract purchased electricity were estimated using the Washington Utilities and Transportation Commission (WUTC) methodologies for purchases and sales of non-firm contract purchased electricity. Regional average emission factors under this methodology are provided by the Department of Commerce using data collected under the fuel mix disclosure law, RCW 19.29A.

5.3.2 Natural Gas Supply

PSE's Scope III CO_2 emissions resulting from the complete combustion or oxidation of natural gas provided to end-users on PSE's distribution systems were calculated using the GHG MRR Subpart NN calculation methodologies (Table B-10). These emissions were calculated based on the amount of natural gas received at the city gate, less the amount delivered to downstream gas transmission pipelines and other local distribution companies (LDCs), less the amount delivered to customers that consume more than 460,000 Mscf of natural gas at a single facility per year, and plus the amount that bypassed the city gate and the net amount retrieved from storage for delivery via PSE's distribution system. Other off-system natural gas that is not delivered to PSE's distribution system was not included in Subpart NN accounting.

6.0 GHG EMISSIONS

PSE's GHG emissions calculations are presented in the following tables.

Table 6-1	Total Emissions by Scope
Table 6-2	Total Emissions by Scope in CO_2 Equivalents (CO_2e)
Table 6-3	Emissions from PSE-Owned Electric Operations
Table 6-4	Emissions from PSE-Owned Natural Gas Operations
Table 6-5	Emissions from Non-Firm Contract Purchased Electricity
Table 6-6	Detailed Emissions Calculations

7.0 Sources and Uncertainties of GHG Emissions

This section evaluates PSE's GHG emissions by source to identify the sources generating the largest amount (ton) and greatest intensity (ton/unit output).

7.1 Sources of GHG Emissions

Table 8 summarizes the GHG emissions from each source category. A majority of the CO_2 emissions were from generated and purchased electricity (63.6%), while the remaining emissions were from natural gas operations and supply (36.4%). For CH_4, the majority of emissions were from fugitive emissions from natural gas operations (80.4%). Generated and purchased electricity accounted for all N_2O and SF_6 emissions. The other two principal GHGs, HFCs and PFCs, were not quantified.

A 100-year GWP (EPA 2014b) (Table A-4) was applied to each GHG to allow for a better comparison among the GHGs and their respective emission sources (Table 9). The GWP is a factor describing the degree of effect a given GHG has on the atmosphere relative to one unit of CO_2. A CO_2 equivalent (CO_2e) is calculated for each GHG so that GHG emissions can be compared on the same basis. In 2019, CO_2 emissions from generated and purchased electricity were the greatest source of GHGs emitted by PSE on a CO_2e basis (68.2%), followed by natural gas supply (31.4%) and natural gas operations (0.4%).

Of PSE's electricity throughput (generated and purchased) in 2019, 62.8% was generated by PSE and 37.2% was purchased (30.1% via firm contracts and 7.1% via non-firm contracts) (Figure 1). Of the CO_2 emissions that are associated with electricity, 64.6% were from electricity generated by PSE and 35.3% were from electricity purchased (29.5% via firm contracts and 5.8% via non-firm contracts) (Figure 1). The relative amount of GHG emissions from the electricity sources did not align with the amount of power from each electricity source. This is due to several factors.

First, about 31.7% of the electricity generated by PSE came from coal combustion (Figure 3), which has a high GHG emission intensity compared to natural gas and oil combustion sources. GHG emission intensity is the relationship between GHG emissions and production, i.e., metric tons CO_2/kWh. Of CO_2 emissions from electricity generated by PSE (direct emissions), about 61.0% were from coal-combustion generation (Figure 3). It is the high GHG emission intensity of coal-combustion generation that made the overall GHG emission intensity of PSE's electric operations high.

Second, about 48.0% of firm contract purchased electricity came from hydroelectric plants in the Pacific Northwest (Figure 4). Hydroelectric generation is considered a non-GHG producing generation source in the GHG inventory. Almost all of the CO_2 emissions generated from firm contract purchased electricity come from coal-combustion generated and natural gas generated electric operations.

Third, regional average emission factors derived by Commerce were used to estimate non-firm contract purchased electricity. Non-firm contract purchased electricity comes from different utilities and non-utilities via the "grid" system of electric distribution. This makes it difficult to track exactly where and how each measure of non-firm contract purchased electricity was generated. For instance, electricity purchased by a utility from an energy trader could have been purchased by the energy trader from a hydroelectric facility near the utility's operational territory, or from a utility generating electricity using coal outside the utility's operational territory. The emissions associated with the generation are not clearly known because they could be significantly different for each source.

Figure 5 shows PSE's generated electricity and firm contract purchased electricity in 2019 by source and the respective CO_2 emissions from each source. The largest source of electricity is coal (36.4%), followed by natural gas/oil generated electricity (33.9%), wind power generated electricity (8.9%), hydroelectricity (18.1%), biogas (0.2%), and other or unknown sources (2.4%). The largest source of CO_2 emissions is from coal-combustion electricity generation (71.3.0%), followed by natural gas electricity generation (26.8%), and other or unknown sources (1.9%).

7.2 Uncertainties in the GHG Emissions Inventory

Uncertainties may exist in the inventory as a result of the following factors:

- Failure to include or properly allocate emission sources within the boundaries of the inventory. Some smaller emission sources were not quantified in the inventory because it was determined that the large effort necessary to estimate their emissions was not warranted by the scale of their potential emissions in relation to the overall inventory.
- Failure to properly estimate emissions from each source. This issue could pertain to inaccurate emission estimation methods or erroneous input data (e.g., fuel throughput) that were used to estimate emissions.

These sources of uncertainty were evaluated for this year's GHG inventory as follows.

7.2.1 Potential Sources of GHG Emissions Not Included

Some small sources of GHG emissions within the inventory boundary were not included in the inventory. HFCs and PFCs emissions from refrigeration equipment leaks and emissions from operation of small engines on portable equipment at remote sites were not included. The effort to gather data to produce emission estimates for these sources would be extremely large relative to the maximum potential GHG emissions from these sources. It appears highly unlikely that these sources of emissions would amount to greater than 5% of PSE's GHG emissions, the threshold for materiality used in the U.S. Department of Energy's (DOE) 1605(b) program. The GHG Protocol does not set a materiality standard. The GHG MRR sets a reporting threshold of 25,000 metric tons of CO_2e per year from an individual source.

Not all of PSE's Scope III emissions were included in this inventory; only those emissions believed to be of significant relevance to PSE's operations were included. Quantification of Scope III emissions is optional under the GHG Protocol. PSE chose to report some Scope III emissions because they amount to a significant portion of the GHG emissions that are affected by PSE's operations due to PSE's purchase of electricity. As an example, Scope III fugitive emissions from PSE-contracted storage at liquefied natural gas facilities were not included in this inventory. These emissions were not expected to present significant uncertainties in the inventory because the scale of potential GHG emissions is relatively low in relation to the overall GHG inventory. Another example, the upstream emissions from the generation of power and production of natural gas were also not included in the Scope III emissions for the PSE inventory. These emissions are not accounted for in this inventory because they are thought to be minor, more uncertain, and further from PSE's control. Other PSE's Scope III emissions may come from emissions associated with employee travel in vehicles other than company vehicles, or emissions associated with wastes. However, as detailed information regarding these emissions are not available and these emissions are thought to be minor in relation to the overall GHG inventory, they were not accounted for in this inventory.

7.2.2 Uncertainty Associated with Data Sources and Methodology

The GHG Protocol specifies that neither assumptions nor methodology should introduce systematic errors that would lead to either high or low estimates of emissions. The methodology generally used to estimate emissions is to apply generally accepted emission factors to translate the amount of activity (e.g., kWh, gallons of fuel) into GHG emissions. The selection of these emission factors was based on assumptions regarding their suitability for the specific application. One of the most likely sources of systematic error can result from the improper use of emission factors, or the use of inaccurate emission factors. Any errors resulting from improper use of emission factors could be evaluated in detail through emissions testing of equipment to develop equipment or source-specific emission factors. However, it is not practical to perform this exercise for each specific emission source in this inventory. This detailed level of evaluation is outside the scope of this inventory. All emission factors used in this inventory are based on commonly accepted practices and best professional judgment to minimize sources of error to the maximum extent possible within the defined scope of the inventory.

Some uncertainty also arises from the methodology used to calculate emissions from non-firm purchases of electricity. As discussed in Section 7.1, regional emission factors were used to estimate emissions from non-firm purchases of electricity. These regional factors were used due to the impracticality of tracking exactly where and how non-firm contract purchased electricity was generated.

8.0 GHG EMISSIONS TIME TRENDS

8.1 Changes in Organizational Boundaries

PSE's organization and operational boundaries change as it builds and purchases new facilities.

In 2005, the Hopkins Ridge wind facility was included in PSE's GHG inventory for the first time. PSE owns 100% of the facility and it was PSE's first wind farm. The facility began generating electricity in November 2005. The Wild Horse wind facility was first included in the 2006 GHG inventory. PSE owns 100% of the facility, which was completed in December 2006. In 2007, the Goldendale natural gas electric generation facility was included in PSE's GHG inventory for the first time. PSE purchased the facility in 2007 and owns 100% of the facility. The Sumas natural gas cogeneration facility was included in the 2008 GHG inventory for the first time. PSE purchased the facility in July 2008 and owns 100% of the facility. The Mint Farm natural gas combined cycle generation facility was purchased in December 2008 and was first included in the 2009 GHG inventory. The Ferndale natural gas cogeneration facility was purchased in November 2012, while Lower Snake River began commercial operations in February 2012.

8.2 Changes in Emissions – 2019 v. 2018

Variation over time is expected in both total emissions and energy generated or consumed by PSE because various factors affect PSE's business, such as weather conditions, power pricing on the energy market, and different power contracts that are written, renewed, or expired. Apart from the factors that affect PSE's business, changes in calculation methodologies should be taken into account when analyzing emission trends. Changes in methodology that have occurred over time in PSE's GHG inventory are provided in Section 8.3.

Overall, PSE's CO2 emissions intensity from total electricity delivered to customers increased from 1,040 lb/MWh to 1,150 lb/MWh. As shown throughout this report, PSE delivers electricity to customers from a combination of sources that the company owns and purchases from other providers via firm contracts or the spot market. In 2019, 62.8% of electricity delivered to PSE customers was generated by the company, while 30.1% of electricity was purchased via firm contracts and 7.1% from non-firm contracts (Figure 1). Of the CO_2 emissions that are associated with electricity, 64.6% were from electricity generated by PSE and 35.3% were from electricity purchased (29.5% via firm contracts and 5.8% via non-firm contracts) (Figure 1).

It's important to remember that CO2 emissions vary based on the fuel source or technology used to generate the electricity. Some sources are more emissions intense than others. "Intensity" is the relationship between emissions and production. For instance, about 36.4% of the electricity generated by PSE came from coal combustion, but this fuel source represented about 71.3% of the CO2 emissions from electricity generated by PSE. Natural gas accounted for 33.9% of the electricity generated by PSE, however this fuel source represented only 26.8% of the CO2 emissions from electricity generated by PSE. Renewable power accounted for 27.3% of the electricity generated by PSE, and produced zero CO2 emissions.

Compared to 2018, total electricity delivered to customers in 2019 decreased by 3.8 percent, and total emissions increased 6.4 percent. This trend is largely due to an increase in natural gas generation owned by PSE, an increase in energy deliveries from Centralia, and a decrease in firm and spot market purchases.

8.3 Changes in Methodology

The methodology used in this year's GHG inventory is consistent with that used to prepare the 2018 GHG inventory with some updates in emission factors.

8.3.1 All Emissions

In the 2009 GHG inventory, the GWPs for CH_4 and N_2O were updated from those provided in the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report - Working Group I Report "The Physical Science Basis," (IPCC 2007) to those provided in the GHG MRR. In 2013, the EPA revised the GHG MRR GWP. Therefore, CH_4 was updated from 23 to 25, N_2O was updated from 310 to 298, and SF_6 was updated from 23,900 to 22,800 (Table A-4). There has been no change in the GHG MRR GWP since 2013.

8.3.2 Scope I (Direct Emissions)

8.3.2.1 Electric Operations

The methodology to estimate PSE's Scope I emissions was consistent from 2002 to 2008. The calculation methodology was changed in the 2009 GHG inventory to align the calculation methodology to those prescribed in the GHG MRR. The following describes the changes in the calculation methodologies in the 2009 GHG inventory. First, the methodology to calculate CH_4 and N_2O emissions from the coal-combustion generation facilities and a group of natural gas/oil generation facilities was changed from using AP-42 emission factors, fuel consumption, and a default high heating value to using the GHG MRR emission factors and unit-specific heat input (Table A-1, Table A-2). Also, for this group of natural gas/oil generation facilities, the methodology to quantify CO_2 emissions was changed from using AP-42 emission factors and fuel consumption to the 40 Code of Federal Regulations (CFR) Part 75 Appendix G method, in which hourly CO_2 emissions are calculated using heat input rate measurements made with certified Appendix D fuel flow meters together with fuel-specific, carbon-based "F-factors." Second, the methodology to quantify CO_2, CH_4, and N_2O emissions for the remaining group of natural gas/oil generation facilities was changed from using AP-42 emission factors, fuel consumption, and a default high heating value to using GHG MRR emission factors, fuel consumption, and unit-specific high heating values. This group of natural gas/oil generation facilities includes the Crystal Mountain, Fredonia 1 and 2, Frederickson 1 and 2, and Whitehorn 2 and 3 facilities.

Beginning in 2011, PSE's Scope I emissions have also included SF_6 emissions from electricity T-D equipment. These emissions were calculated using the GHG MRR Subpart DD calculation methodologies (Table B-9).

In this year's GHG inventory, there was no change in calculation methodology for Scope I electric operations.

8.3.2.2 Natural Gas Operations

In the 2009 GHG inventory, the heating value of natural gas delivered to consumers was updated from 1,026 British thermal unit per cubic feet (Btu/ft^3) to 1,027 Btu/ft^3, as provided in the Natural Gas Annual 2008 (DOE/EIA 2010a). In the 2010 GHG inventory, the heating value was updated to 1,025 Btu/ft^3, as provided in the Natural Gas Annual 2009 (DOE/EIA 2010b). In the 2011 GHG inventory, the heating value of natural gas delivered to consumers remained unchanged. In the 2012 GHG inventory, the heating value was updated to 1,029 Btu/ft^3, as provided in the Natural Gas Annual 2011 (DOE/EIA 2013). In the 2013 GHG inventory, the heating value of natural gas delivered to consumers remained unchanged. In the 2014 GHG inventory, the heating value was updated to 1,030 Btu/ft^3, as provided in the Natural Gas Annual 2013 (DOE/EIA 2013). The Natural Gas Annual 2014 (DOE/EIA 2014) updated the heating value to 1,044 Btu/ft^3 and was changed in the 2015 GHG inventory. In the 2016 inventory, the heating value of natural gas was updated to 1,065 Btu/ft^3 as reflected in the Natural Gas Annual 2015 (DOE/EIA 2015). For the 2019 inventory, the heating value of natural gas was updated to 1,078 Btu/ft^3 as reflected in the Natural Gas Annual 2016 (DOE/EIA 2016, p. 52).

Beginning in 2011, the calculation methodology to estimate PSE's Scope I emissions from natural gas operations was changed to align to that prescribed in the GHG MRR. GHG emissions from natural gas storage were removed, and GHG emissions from natural gas distribution were calculated using the GHG MRR Subpart W calculation methodologies.

In this year's GHG inventory, there was no change in calculation methodology.

8.3.2.3 Other Scope I Emissions

In the 2007 and previous GHG inventories, vehicle fleet emissions were calculated based on the vehicles' fuel consumption and emission factors from the GHG Protocol. In 2008, vehicle fleet emissions were calculated using the Greenhouse Gas On-Road Motor Vehicles Emissions Calculator (Ecology 2009) developed by Ecology. The calculator provides a convenient platform to estimate GHG emissions using fuel data. It also allows the estimation of CH_4 and N_2O emissions from the vehicle fleet, which could not be quantified in the 2007 and previous inventories.

Beginning in 2009, vehicle fleet emissions were not calculated within PSE's GHG inventory. PSE elected not to include these emissions in the GHG inventory for two reasons. First, historically, vehicle fleet emissions totaled approximately 0.1% of PSE's total emissions output, which is below the de minimis level of 2% that is recognized by the GHG Protocol. Second, the GHG MRR will account for emissions from the transportation sector further up the production stream with a method that is more accurate than the approach recommended by the GHG Protocol. Therefore, vehicle fleet emissions were not included to ensure accurate and consistent reporting and avoid double counting.

In this year's GHG inventory, there was no change in calculation methodology for Other Scope I emissions.

8.3.3 Scope III (Other Indirect Emissions)

8.3.3.1 Electric Operations

The methodology used to estimate PSE's Scope III emissions from firm contract purchased electricity has changed over time. In the 2002 GHG inventory, the amount of electricity purchased from each source was not available, so electricity throughput and emissions were estimated based on the relative size of known contracts. In the 2003 GHG inventory, records of the amount of electricity purchased from each source were available except for non-utility (Public Utility Regulatory Policies Act [PURPA]) contracts. Only a lump sum was available for electricity purchased via PURPA contracts. This is the same as for the 2004 GHG inventory. Therefore, in the 2003 and 2004 GHG inventories, fuel-specific (e.g., coal, oil, gas) emission factors were used to estimate emissions from non-PURPA firm contract purchased electricity. Since the 2005 GHG inventory, detailed information regarding the source-technology for electricity purchased via PURPA contracts was available, so this information has since been used to estimate emissions for the inventories.

With the exception of the 2003 and 2004 GHG inventories, the methodology used to estimate PSE's Scope III emissions from non-firm contract purchased electricity has been consistent. In the 2002 GHG inventory, no data on the source of non-firm contract purchased electricity were available, so the emissions were estimated using national average emission factors. In the 2003 and 2004 GHG inventories, data on the source of non-firm contract purchased electricity were available, so fuel-specific emission factors were used to estimate emissions. Since the 2005 GHG inventory, no data on the source of non-firm contract purchased electricity were available. As a result, the Western Electricity Coordinating Council (WECC) regional average emission factor (Table 6) was used to estimate emissions. It is assumed that the same data will be available in the future, so future emission inventories should continue to use the WECC regional emission factor or equivalent to calculate emissions associated with non-firm contracts. This will produce consistency in the calculation methodology and make results more comparable over time.

In the 2004 inventory, the accounting of purchased electricity for resale included a slightly modified approach. The 2002 through 2003 and 2005 through 2009 GHG inventories all used the same methodology for purchased electricity for resale.

In the 2007 inventory, the eGRID emission factor for calculating emissions from firm and non-firm contract purchases was updated. Specifically, the eGRID emission factor for CO_2 emissions was updated from 1.027 lb/MWh for the WECC subregion in EPA Sixth Edition eGRID2007 Version 1.0 (EPA 2008a) to 0.902 lb/MWh for the Northwest Power Pool (NWPP) WECC Northwest subregion in EPA eGRID2007 Version 1.1 (EPA 2008b).

In the 2010 GHG inventory, the heat rates used to calculate emission factors for firm and non-firm contracts purchased electricity were updated. The heat rates were updated from: 9,425 Btu/kWh to 9,200 Btu/kWh for coal, 11,700 Btu/kWh to 10,788 Btu/kWh for semi-closed gas turbine (SCGT), 6,900 Btu/kWh to 6,752 Btu/kWh for combined cycle gas turbine (CCGT), 14,500 Btu/kWh to 9,451 Btu/kWh for biomass, and 11,700 Btu/kWh to 10,788 Btu/kWh for petroleum.

In the 2011 GHG inventory, the eGRID emission factor for CO_2 emissions was updated to 0.859 lb/MWh for the NWPP WECC Northwest subregion in EPA Seventh Edition eGRID2010 Version 1.0 (EPA 2011).

In the 2012 GHG inventory, the eGRID emission factor for CO_2 emissions was updated to 0.819 lb/MWh for the NWPP WECC Northwest subregion in EPA Eighth Edition eGRID2012 Version 1.0 (EPA 2012). Also, the heat rates used to calculate emission factors for firm and non-firm contracts purchased electricity were updated. The heat rates were updated from: 9,200 Btu/kWh to 8,800 Btu/kWh for coal, 10,788 Btu/kWh to 10,745 Btu/kWh for SCGT, 6,752 Btu/kWh to 6,430 Btu/kWh for CCGT, 9,451 Btu/kWh to 13,500 Btu/kWh for biomass, and 10,788 Btu/kWh to 10,745 Btu/kWh for petroleum.

In the 2013 GHG inventory, the eGRID emission factor for CO_2 emissions was updated to 0.843 lb/MWh for the NWPP WECC Northwest subregion in EPA Ninth Edition eGRID Version 1.0 (EPA 2014a).

In the 2014 inventory, the eGRID emission factor for CO_2 emissions was updated to 0.666 lb/MWh for the NWPP WECC Northwest subregion in EPA eGRID2012 (EPA 2015a). Also, the heat rates used to calculate emission factors for firm and non-firm contracts purchased electricity were updated. The heat rates were updated from: 10,745 Btu/kWh to 10,783 Btu/kWh for SCGT and 10,745 Btu/kWh to 10,783 Btu/kWh for petroleum.

In the 2016 inventory, the CO_2 eGRID emission factor was updated to 0.907 lb/kWh for the NWPP WECC Northwest subregion in EPA eGRID (EPA 2017). Heat rates in the 2016 Assumptions to the Annual Energy Outlook (EIA 2016) were updated from: 10,783 Btu/kWh to 9,960 Btu/kWh for SCGT, 6,430 Btu/kWh to 6,300 Btu/kWh for CCGT, and 10,783 Btu/kWh to 9,960 Btu/kWh for petroleum.

For the 2019 inventory, the CO_2 grid emission factor was updated to 976 lb/MWh for the WECC NWPP subregion as published by Commerce. Heat rates in the 2017 Assumptions to the Annual Energy Outlook (EIA 2017, Table A.3) were updated to: 9,920 Btu/kWh for SCGT, 6,600 Btu/kWh for CCGT, and 9,920 Btu/kWh for petroleum.

8.3.3.2 Natural Gas Supply

PSE's Scope III emissions associated with natural gas supply include CO_2 emissions that would result from the complete use of natural gas provided to end-users on their distribution systems. This source of emissions was included in the GHG inventory for the first time in 2010.

In this year's GHG inventory, there was no change in calculation methodology for Scope III natural gas supply.

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Sources and Uncertainties of GHG Emissions

Table ES-1. Calendar Year 2019 Operating Rates

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Operating Statistics [1]	Electric Operations	Natural Gas Operations
Throughput	22,307,029,589 kWh	117,866,839 Mscf
Customers Served (Average)	1,165,699	841,427
Combined Emissions (metric ton)		
Carbon Dioxide (CO_2)	17,282,988	
Methane (CH_4)	3,433	
Nitrous Oxide (N_2O)	140	
Sulfur Hexafluoride (SF_6)	0.012	

Data Source:
[1] Puget Energy Form 10-K

Table ES-2. Calendar Year 2019 Greenhouse Gas Emissions by Scope

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Emission Source	Emissions							
	CO_2		CH_4		N_2O		SF_6	
	(metric ton)	(%) [(2)]	(metric ton)	(%) [(2)]	(metric ton)	(%) [(2)]	(metric ton)	(%) [(2)]
Scope I								
Electric Operations								
Hydro	0	0%	0	0%	0	0%	0	0%
Coal	4,496,229	61.0%	520	17%	76	94%	0	0%
Natural Gas/ Oil	2,871,386	39%	51	2%	5.1	6%	0	0%
Wind	0	0%	0	0%	0	0%	0	0%
Electrical Transmission and Distribution Equipment	0	0%	0	0%	0	0%	0.01	100%
Total Scope I - PSE-owned Electric Operations	**7,367,614**	**100%**	**571**	**19%**	**81**	**100%**	**0.01**	**100%**
Natural Gas Operations								
Distribution	74	0.00%	2,453	81%	0	0%	0	NC
Total Scope I - PSE-owned Natural Gas Operations	**74**	**0%**	**2,453**	**81%**	**0**	**0%**	**0**	**NC**
Total Scope I	**7,367,688**	**100%**	**3,024**	**100%**	**81**	**100%**	**0.01**	**100%**
Scope III								
Electric Operations								
Firm Contracts	3,753,822	38%	409	100%	59	100%	0	NC
Non-Firm Contracts	1,045,665	11%	0	0%	0	0%	0	NC
Total Scope III - Electricity Purchases	**4,799,488**	**48%**	**409**	**100%**	**59**	**100%**	**0**	**NC**
Natural Gas Supply								
Supply to End-Users	5,115,812	52%	0	0%	0	0%	0	NC
Total Scope III - Natural Gas Supply	**5,115,812**	**52%**	**0**	**0%**	**0**	**0%**	**0**	**NC**
Total Scope III	**9,915,300**	**100%**	**409**	**100%**	**59**	**100%**	**0**	**NC**
Outside Scope								
Non-Firm Transport Gas	1,207,354	100%	0	NC	0	NC	0	NC
Total Outside Scope - Non-Firm Transport Gas	**1,207,354**	**NC**	**0**	**NC**	**0**	**NC**	**0**	**NC**

Note(s):
(1) Consistent with the GHG Protocol, only CO_2 is accounted separately for biomass generation
(2) Percentage of emissions in scope
(3) NC = Not calculated

Table ES-3. Calendar Year 2019 Greenhouse Gas Emissions by Source

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Emission Source	Emissions							
	CO_2		CH_4		N_2O		SF_6	
	(metric ton)	(%)	(metric ton)	(%)	(metric ton)	(%)	(metric ton)	(%)
Electrical Transmission and Distribution Equipment	0	0%	0	0%	0	0%	0.01	100%
Total - PSE-owned Electric Operations	**7,367,614**	**42.6%**	**571**	**16.6%**	**81**	**57.6%**	**0**	**100%**
Firm & Non-Firm Contracts Purchases								
Firm Contracts	3,753,822	21.7%	409	11.9%	59	42.4%	0	0%
Non-Firm Contracts	1,045,665	6.1%	0	0.0%	0	0.0%	0	0%
Total - Firm & Non-Firm Contracts Purchases	**4,799,488**	**27.8%**	**409**	**11.9%**	**59**	**42.4%**	**0**	**0%**
Total - Generated and Purchased Electricity	**12,167,102**	**70.4%**	**980**	**28.5%**	**140**	**100%**	**0.01**	**100%**
Natural Gas Operations								
Distribution and Storage of PSE-owned Natural Gas Operations								
Distribution	74	0.0004%	2,453	71.5%	0	0%	0	0%
Total - Natural Gas Operations	**74**	**0.0004%**	**2,453**	**71.5%**	**0**	**0%**	**0**	**0%**
Natural Gas Supply								
Supply to End-Users	5,115,812	29.6%	0	0%	0	0%	0	0%
Total - Natural Gas Supply	**5,115,812**	**29.6%**	**0**	**0%**	**0**	**0%**	**0**	**0%**
Emissions from All Sources	**17,282,988**	**100%**	**3,433**	**100%**	**140**	**100%**	**0.01**	**100%**

Note(s):
(1) NC = Not calculated

Table 1. Calendar Year 2019 Sources of Emissions Accounted

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Operational Boundary	Greenhouse Gases					
	CO_2	CH_4	N_2O	SF_6	HFCs [2]	PFCs [2]
Scope I (Direct Emissions)						
Emissions from PSE-Owned Electric Operations	X	X	X	X		
Emissions from PSE-Owned Natural Gas Operations	X	X				
Emissions from Fleet Vehicle Use [3]						
Scope II (Indirect Emissions)						
Emissions from Purchased Electricity Used by PSE	X [1]	X [1]	X [1]			
Scope III (Indirect Emissions)						
Emissions from Purchased Electricity Sold to Others	X	X	X			
Fugitive Emissions from Distribution of Natural Gas Owned by Others						
Fugitive Emissions from Storage of PSE-Owned Natural Gas by Others						
Emissions from Combustion of Natural Gas Supplied to End-Users	X					
Outside Scope (Emissions from Biomass)						
Emissions from Purchased Electricity Generated from Biomass	X	X	X			

Note(s):
(1) Included in Scope I and Scope III. Not reported in Scope II.
(2) HFCs and PFCs are not included in this inventory because PSE's emissions of these GHGs are negligible.
(3) PSE elected not to calculate emissions from fleet vehicles as they are minimal.

Table 2. Total Emissions by Scope

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Emission Source	Energy Amount	(UOM)	Emissions CO_2 (metric ton)	CO_2 (%) [2]	CH_4 (metric ton)	CH_4 (%) [2]	N_2O (metric ton)	N_2O (%) [2]	SF_6 (metric ton)	SF_6 (%) [2]	Emission Intensity CO_2	(UOM)	CH_4	(UOM)	N_2O	(UOM)	SF_6	(UOM)
Scope I																		
Electric Operations																		
Hydro	712,727,200	kWh	0	0%	0	0%	0	0%	0	0%	0.000	lb/kWh	0.0E+00	lb/kWh	0.0E+00	lb/kWh	0.0	lb/kWh
Coal	4,251,239,000	kWh	4,496,229	61%	520	17%	76	94%	0	0%	2.332	lb/kWh	2.7E-04	lb/kWh	3.9E-05	lb/kWh	0.0	lb/kWh
Natural Gas/ Oil	6,799,329,148	kWh	2,871,386	39%	51	2%	5.1	6%	0	0%	0.931	lb/kWh	1.7E-05	lb/kWh	1.7E-06	lb/kWh	0.0	lb/kWh
Wind	1,667,488,792	kWh	0	0%	0	0%	0	0%	0	0%	0.000	lb/kWh	0.0E+00	lb/kWh	0.0E+00	lb/kWh	0.0	lb/kWh
Electrical Transmission and Distribution Equipment	0	kWh	0	0%	0	0%	0	0%	0.012	100%	NC		NC		NC		NC	
Total Scope I - PSE-owned Electric Operations	**13,430,784,140**	**kWh**	**7,367,614**	**100%**	**571**	**19%**	**81**	**100%**	**0.0**	**100%**	**1.209**	**lb/kWh**	**9.4E-05**	**lb/kWh**	**1.3E-05**	**lb/kWh**	**NC**	**lb/kWh**
Natural Gas Operations																		
Distribution	117,866,839	thm	74	0%	2,453	81%	0	0%	0	NC	0.001	lb/thm	0.046	lb/thm	0.0E+00	lb/thm	0.0	lb/thm
Total Scope I - PSE-owned Natural Gas Operations	**117,866,839**	**thm**	**74**	**0%**	**2453**	**81%**	**0**	**0%**	**0**	**NC**	**0.001**	**lb/thm**	**0.046**	**lb/thm**	**0.0E+00**	**lb/thm**	**0**	**lb/thm**
Total Scope I			**7,367,688**	**100%**	**3,024**	**100%**	**81**	**100%**	**0.0**	**100%**								
Scope III																		
Electric Operations																		
Firm Contracts[3]	6,597,362,483	kWh	3,753,822	38%	409	100%	59	100%	0	NC	1.254	lb/kWh	1.4E-04	lb/kWh	2.0E-05	lb/kWh	0.0	lb/kWh
Non-Firm Contracts[3]	2,278,882,966	kWh	1,045,665	11%	0	0%	0	0%	0	NC	1.012	lb/kWh	0.0E+00	lb/kWh	0.0E+00	lb/kWh	0.0	lb/kWh
Total Scope III - Electricity Purchases	**8,876,245,449**	**kWh**	**4,799,488**	**48%**	**409**	**100%**	**59**	**100%**	**0**	**NC**	**1.192**	**lb/kWh**	**1.0E-04**	**lb/kWh**	**1.5E-05**	**lb/kWh**	**NC**	**lb/kWh**
Natural Gas Supply																		
Supply to End-Users	940,406,665	thm	5,115,812	52%	0	0%	0	0%	0	NC	12.0	lb/thm	0.0	lb/thm	0.0	lb/thm	0.0	lb/thm
Total Scope III - Natural Gas Supply	**940,406,665**	**thm**	**5,115,812**	**52%**	**0**	**0%**	**0**	**0%**	**0**	**NC**	**12.0**	**lb/thm**	**0.0**	**lb/thm**	**0.0**	**lb/thm**	**0**	**lb/thm**
Total Scope III			**9,915,300**	**100%**	**409**	**100%**	**59**	**100%**	**0**	**NC**								
Outside Scope																		
Non-Firm Transport Gas	22,194,007	Mscf	1,207,354	100%	0	NC	0	NC	0	NC	0	NC	0	NC	0	NC	0	NC
Total Outside Scope			**1,207,354**	**NC**	**0**	**NC**	**0**	**NC**	**0**	**NC**	**0**	**NC**	**0**	**NC**	**0**	**NC**	**0**	**NC**
All Electric			**12,167,102**	**NC**	**980**	**NC**	**140**	**NC**	**0**	**NC**								
All Natural Gas Supply			**6,323,240**	**NC**	**2,453**	**NC**	**0**	**NC**	**0**	**NC**								

Note(s):

(1) NC = Not calculated

(2) Percentage of emissions in CO_2e in scope

(3) Includes transmission losses

Table 3. Total Emissions by Scope in CO2 Equivalents (CO2e)

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Emission Source	Energy Amount	(UOM)	Emissions in CO_2 Equivalents (CO_2e) - 100-Year Timeframe (Tons): CO_2 (metric ton)	CO_2 (%) [2]	CH_4 (metric ton)	CH_4 (%) [2]	N_2O (metric ton)	N_2O (%) [2]	SF_6 (metric ton)	SF_6 (%) [2]	Total (metric ton)	Total (%) [2]	Emission Intensity Total	(UOM)
Scope I														
Electric Operations														
Hydro	712,727,200	kWh	0	0%	0	0%	0	0%	0	0%	0	0%	0	lb/kWh
Coal	4,251,239,000	kWh	4,496,229	60%	13,000	0.2%	22,543	0.3%	0	0%	4,531,772	60.7%	2.350	lb/kWh
Natural Gas/ Oil	6,799,329,148	kWh	2,871,386	38%	1,274	0.02%	1,520	0.02%	0	0%	2,874,180	38.5%	0.932	lb/kWh
Wind	1,667,488,792	kWh	0	0%	0	0%	0	0%	0	0%	0	0%	0	lb/kWh
Electrical Transmission and Distribution Equipment	0	kWh	0	0%	0	0%	0	0%	265	0.0%	265	0.004%	NC	
Total Scope I - PSE-owned Electric Operations	**13,430,784,140**	**kWh**	**7,367,614**	**99%**	**14,275**	**0.2%**	**24,063**	**0.3%**	**265**	**0.0%**	**7,406,217**	**99.2%**	**1.216**	**lb/kWh**
Natural Gas Operations														
Distribution	117,866,839	thm	74	0.001%	61,331	0.8%	0	0%	0	0%	61,405	0.8%	1.149	lb/thm
											0	0.0%		
Total Scope I - PSE-owned Natural Gas Operations	**117,866,839**	**thm**	**74**	**0.001%**	**61,331**	**0.8%**	**0**	**0%**	**0**	**0%**	**61,405**	**0.8%**	**1.149**	**lb/thm**
Total Scope I			**7,367,688**	**99%**	**75,606**	**1.0%**	**24,063**	**0.3%**	**265**	**0.0%**	**7,467,622**	**100.00%**		
Scope III														
Electric Operations														
Firm Contracts[3]	6,597,362,483	kWh	3,753,822	38%	10,224	0.10%	17,727	0.2%	0	0%	3,781,773	38.0%	1.264	lb/kWh
Non-Firm Contracts[3]	2,278,882,966	kWh	1,045,665	11%	0	0.00%	0	0.0%	0	0%	1,045,665	10.5%	1.012	lb/kWh
Total Scope III - Electricity Purchases	**8,876,245,449**	**kWh**	**4,799,488**	**48%**	**10,224**	**0.10%**	**17,727**	**0.2%**	**0**	**0%**	**4,827,439**	**48.5%**	**1.199**	**lb/kWh**
Natural Gas Supply														
Supply to End-Users	940,406,665	thm	5,115,812	51%	0	0%	0	0%	0	0%	5,115,812	51.5%	12.0	lb/thm
Total Scope III - Natural Gas Supply	**940,406,665**	**thm**	**5,115,812**	**51%**	**0**	**0%**	**0**	**0%**	**0**	**0%**	**5,115,812**	**51.5%**	**12.0**	**lb/thm**
Total Scope III			**9,915,300**	**100%**	**10,224**	**0.10%**	**17,727**	**0.2%**	**0**	**0%**	**9,943,251**	**100.0%**		
Outside Scope														
Non-Firm Transport Gas	22,194,007	Mscf	1,207,354	NC	0	NC	0	NC	0	NC	0	NC	0.0	NC
Total Outside Scope			**1,207,354**	**NC**	**0**	**NC**	**0**	**NC**	**0**	**NC**	**0**	**NC**	**0**	**NC**

Data Source:
[1] EPA GHG MRR Subpart A (40 CFR 98), Table A-1

Note(s):
(1) NC = Not calculated
(2) Percentage of emissions in CO_2e in scope
(3) Includes transmission losses

Global Warming Potentials [1]:

Time Horizon	CO_2	CH_4	N_2O	SF_6
100 years	1	25	298	22,800

Table 4. Emissions from PSE-Owned Electric Operations

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Emission Source	Energy Amount [1] (kWh)	PSE Share [2] (%)	PSE Share of Emissions [1] CO_2 (metric ton)	CO_2 (%) [5]	CH_4 (metric ton)	CH_4 (%) [5]	N_2O (metric ton)	N_2O (%) [5]	SF_6 (metric ton)	SF_6 (%) [5]	Emission Intensity CO_2 (lb/kWh)	CH_4 (lb/kWh)	N_2O (lb/kWh)	SF_6 (lb/kWh)
Hydro														
Hydro	712,727,200	100%	0	0%	0	0%	0	0%	0	0%	0	0	0	0
Total Hydro	**712,727,200**		**0**	**0%**	**0**	**0%**	**0**	**0%**	**0**	**0%**	**0**	**0**	**0**	**0**
Coal [2]														
Colstrip Unit 1	738,901,000	50%	923,568	13%	107	19%	16	19%	0	0%	2.8	3.2E-04	4.6E-05	0
Colstrip Unit 2	898,946,000	50%	984,966	13%	114	20%	17	21%	0	0%	2.4	2.8E-04	4.1E-05	0
Colstrip Unit 3	1,354,739,000	25%	1,314,441	18%	152	27%	22	27%	0	0%	2.1	2.5E-04	3.6E-05	0
Colstrip Unit 4	1,258,653,000	25%	1,273,254	17%	147	26%	21	27%	0	0%	2.2	2.6E-04	3.8E-05	0
Total Coal	**4,251,239,000**		**4,496,229**	**61%**	**520**	**91%**	**76**	**94%**	**0**	**0%**	**2.3**	**2.7E-04**	**3.9E-05**	**0**
Natural Gas/ Oil [3]														
Crystal Mountain	185,520	100%	154	0%	0.01	0.0%	0.001	0.0%	0	0%	1.8	7.4E-05	1.5E-05	0
Encogen 1	135,883,363	100%	63,916	1%	1.2	0.2%	0.1	0.1%	0	0%	1.0	1.9E-05	1.9E-06	0
Encogen 2	131,562,333	100%	62,070	1%	1.2	0.2%	0.1	0.1%	0	0%	1.0	1.9E-05	1.9E-06	0
Encogen 3	135,578,333	100%	65,527	1%	1.2	0.2%	0.1	0.15%	0	0%	1.1	2.0E-05	2.0E-06	0
Ferndale 1	535,488,500	100%	238,067	3%	4.4	0.77%	0.4	0.55%	0	0%	1.0	1.8E-05	1.8E-06	0
Ferndale 2	530,603,500	100%	239,722	3%	4.4	0.78%	0.4	0.55%	0	0%	1.0	1.8E-05	1.8E-06	0
Frederickson 1	50,624,000	100%	40,013	1%	0.8	0.1%	0.08	0.1%	0	0%	1.7	3.3E-05	3.3E-06	0
Frederickson 2	33,571,600	100%	29,945	0%	0.6	0.1%	0.06	0.1%	0	0%	2.0	3.7E-05	3.7E-06	0
Fredonia 1	54,580,200	100%	41,726	1%	0.8	0.1%	0.1	0.1%	0	0%	1.7	3.2E-05	3.2E-06	0
Fredonia 2	111,955,500	100%	94,515	1%	1.8	0.3%	0.2	0.2%	0	0%	1.9	3.5E-05	3.5E-06	0
Fredonia 3	3,591,700	100%	1,706	0%	0.0	0.01%	0.0	0.00%	0	0%	1.0	2.2E-05	2.2E-06	0
Fredonia 4	29,791,300	100%	16,437	0%	0.3	0.05%	0.0	0.04%	0	0%	1.2	2.2E-05	2.2E-06	0
Frederickson Unit 1	669,752,198	49.85%	256,218	3%	2.4	0.4%	0.2	0.3%	0	0%	0.8	7.8E-06	7.8E-07	0
Goldendale	1,942,118,000	100%	728,383	10%	13.5	2.4%	1.4	1.7%	0	0%	0.8	1.5E-05	1.5E-06	0
Mint Farm	1,930,573,500	100%	758,676	10%	14.1	2.5%	1.4	1.7%	0	0%	0.9	1.6E-05	1.6E-06	0
Sumas	494,780,200	100%	227,481	3%	4.2	0.7%	0.4	0.5%	0	0%	1.0	1.9E-05	1.9E-06	0
Whitehorn 2	4,913,300	100%	3,671	0%	0.1	0.0%	0.01	0.0%	0	0%	1.6	3.1E-05	3.2E-06	0
Whitehorn 3	3,776,100	100%	3,159	0%	0.1	0.0%	0.01	0.0%	0	0%	1.8	4.1E-05	5.4E-06	0
Total Natural Gas/ Oil	**6,799,329,148**		**2,871,386**	**39%**	**51**	**9%**	**5.1**	**6%**	**0**	**0%**	**0.9**	**1.7E-05**	**1.7E-06**	**0**
Wind														
Wild Horse	612,886,218	100%	0	0%	0	0%	0	0%	0	0%	0	0	0	0
Lower Snake River	714,103,694	100%	0	0%	0	0%	0	0%	0	0%	0	0	0	0
Hopkins Ridge	340,498,880	100%	0	0%	0	0%	0	0%	0	0%	0	0	0	0
Total Wind	**1,667,488,792**		**0**	**0%**	**0**	**0%**	**0**	**0%**	**0**	**0%**	**0**	**0**	**0**	**0**
Electrical Transmission and Distribution Equipment [4]														
All equipment	0	100%	0	0%	0	0%	0	0%	0.0	100%	NC	NC	NC	NC
Total Electrical Transmission and Distribution Equipment			**0**	**0%**	**0**	**0%**	**0**	**0%**	**0.0**	**100%**	**NC**	**NC**	**NC**	**NC**
Total PSE-Owned Electric Operations	**13,430,784,140**		**7,367,614**	**100%**	**571**	**100%**	**81**	**100%**	**0.0**	**100%**	**1.2**	**9.4E-05**	**1.3E-05**	**1.9E-09**

Data Source:
[1] Summary of Generation, Power Cost Report (PSE)
[2] Puget Energy Annual Form 10-K

Note(s):
(1) Calculated according to PSE's owned portion of the facility using the WRI/WBCSD GHG Protocol equity share method
(2) See Table A-1 for calculation details
(3) See Table A-2 for calculation details
(4) See Table B-8 for calculation details
(5) Percentage of emissions among PSE-owned electric operations
(6) NC = Not calculated

Table 5. Emissions from PSE-Owned Natural Gas Operations

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Emission Source	Count	Emissions [2]				Emissions in CO_2 Equivalents (CO_2e) - 100-Year Timeframe (Tons) [2]					
		CO_2		CH_4		CO_2		CH_4		Total	
		(metric ton)	(%) [3]	(metric ton)	(%) [3]	(metric ton)	(%) [4]	(metric ton)	(%) [4]	(metric ton)	(%) [4]
Below Grade M&R Station [2]											
Below Grade M&R Station Components > 300 psig	3	0.02	0.03%	0.7	0.03%	0.02	0.00003%	16	0.03%	16	0.03%
Below Grade M&R Station Components 100 - 300 psig	354	0.4	0.5%	12	0.5%	0.4	0.001%	298	0.5%	298	0.5%
Below Grade M&R Station Components < 100 psig	12	0.01	0.01%	0	0.01%	0.01	0.00001%	5	0.01%	5	0.01%
Total Below Grade M&R Station	**369**	**0.4**	**1%**	**13**	**1%**	**0.4**	**0%**	**319**	**1%**	**320**	**1%**
Distribution Mains [1]											
Unprotected Steel	0	0	0%	0	0%	0	0%	0	0%	0	0%
Protected Steel	4,069	7.2	10%	240	10%	7.2	0.01%	5,988	10%	5,996	10%
Plastic	8,825	51	68%	1,677	68%	51	0.1%	41,932	68%	41,983	68%
Cast Iron	0	0	0%	0	0%	0	0%	0	0%	0	0%
Total Distribution Mains	**12,894**	**58**	**78%**	**1,917**	**78%**	**58**	**0.1%**	**47,921**	**78%**	**47,978**	**78%**
Distribution Services [1]											
Unprotected Steel	0	0	0%	0	0%	0	0%	0	0%	0	0%
Protected Steel	120,549	12	17%	406	17%	12	0.02%	10,138	17%	10,150	17%
Plastic	702,397	3.6	4.8%	118	4.8%	3.6	0.01%	2,953	5%	2,957	5%
Copper	0	0	0%	0	0%	0	0%	0	0%	0	0%
Total Distribution Services	**822,946**	**16**	**21%**	**524**	**21%**	**16**	**0.03%**	**13,091**	**21%**	**13,107**	**21%**
Total PSE-Owned Natural Gas Operations		**74**	**100%**	**2,453**	**100%**	**74**	**0.1%**	**61,331**	**100%**	**61,405**	**100%**

Data Source:
[1] Subpart W Reporting Form
[2] Annual M&R Survey (PSE)
[3] EPA GHG MRR Subpart A (40 CFR 98), Table A-1

Global Warming Potentials [3]:

Time Horizon	CO_2	CH_4	N_2O	SF_6
100 years	1	25	298	22,800

Note(s):
(1) Count represents number of leaking components
(2) See Table B-8 for calculation details
(3) Percentage of emissions among PSE-owned natural gas operations
(4) Percentage of emissions in CO_2e among PSE-owned natural gas operations
(5) NC = Not calculated
(6) M&R = Metering-regulating

Table 6. Emissions from Non-Firm Contract Purchased Electricity

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Non-Firm Contract Purchased Electricity: 2,278,882,966 kWh

Emission Source	Emissions		
	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)
Non-Firm Contract Purchased Electricity	995,872	11.47	19.85

Emission Factors:

Fuel Type	CO_2 (lb/kWh)	CH_4 (lb/kWh)	N_2O (lb/kWh)
Other (1)	0.963 [1]	1.11E-05 [2]	1.92E-05 [2]

Data Source:
[1] Unspecified Emission Rate (SB 5116, May 7, 2019)
[2] Updated State-level Greenhouse Gas Emission Coefficients for Electricity Generation 1998-2000, Table 1 (DOE/EIA April 2002)

Note(s):
(1) Assume other fuel type, see Table A-3

Table 7. Detailed Emissions Calculations

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Emission Source	Source (Detailed)	Energy Amount (kWh)	Total % of Total Power	% of Generation or Purchase	Total CO_2 (metric ton)	Total CH_4 (metric ton)	Total N_2O (metric ton)	Total CO_2e (metric ton)
PSE GENERATION								
Hydro [1]	***POWER COST***	**712,727,200**	**3.2%**	**5.3%**	**0**	**0**	**0**	**0**
	PSE Hydro	712,727,200	3.2%	5.3%	0	0	0	0
Coal [2]	***GADS***	**4,251,239,000**	**19.1%**	**31.7%**	**4,496,229**	**520.0**	**75.6**	**4,531,772**
	Colstrip Unit 1	738,901,000	3.3%	5.5%	923,568	106.9	15.5	930,872
	Colstrip Unit 2	898,946,000	4.0%	6.7%	984,966	113.9	16.6	992,753
	Colstrip Unit 3	1,354,739,000	6.1%	10.1%	1,314,441	152.0	22.1	1,324,830
	Colstrip Unit 4	1,258,653,000	5.6%	9.4%	1,273,254	147.2	21.4	1,283,317
Natural Gas/ Oil [1],[3]	***GADS***	**6,799,329,148**	**30.5%**	**50.6%**	**2,871,385.7**	**51.0**	**5.1**	**2,874,180.2**
	Crystal Mountain	185,520	0.0%	0.0%	154	0.01	0.001	154.6
	Encogen 1	135,883,363	0.6%	1.0%	63,916	1.2	0.1186	63,980.8
	Encogen 2	131,562,333	0.6%	1.0%	62,070	1.2	0.1151	62,133.5
	Encogen 3	135,578,333	0.6%	1.0%	65,527	1.2	0.1215	65,593.7
	Ferndale 1	535,488,500	2.4%	4.0%	238,067	4.4	0.4416	238,309.3
	Ferndale 2	530,603,500	2.4%	4.0%	239,722	4.4	0.4446	239,965.2
	Frederickson 1	50,624,000	0.2%	0.4%	40,013	0.8	0.0766	40,055.3
	Frederickson 2	33,571,600	0.2%	0.2%	29,945	0.6	0.0564	29,975.8
	Fredonia 1	54,580,200	0.2%	0.4%	41,726	0.8	0.0802	41,769.3
	Fredonia 2	111,955,500	0.5%	0.8%	94,515	1.8	0.1784	94,613.1
	Fredonia 3	3,591,700	0.0%	0.0%	1,706	0.0	0.0036	1,707.9
	Fredonia 4	29,791,300	0.1%	0.2%	16,437	0.3	0.0304	16,453.5
	Frederickson Unit 1	669,752,198	3.0%	5.0%	256,218	2.4	0.2369	256,347.7
	Goldendale	1,942,118,000	8.7%	14.5%	728,383	13.5	1.3510	729,123.0
	Mint Farm	1,930,573,500	8.7%	14.4%	758,676	14.1	1.4072	759,447.1
	Sumas	494,780,200	2.2%	3.7%	227,481	4.2	0.4219	227,711.9
	Whitehorn 2	4,913,300	0.0%	0.0%	3,671	0.1	0.0072	3,674.9
	Whitehorn 3	3,776,100	0.0%	0.0%	3,159	0.1	0.0092	3,163.6
Wind [1]	***POWER COST***	**1,667,488,792**	**7.5%**	**12.4%**	**0**	**0**	**0**	**0**
	Wild Horse (W183)	612,886,218	2.7%	4.6%	0	0	0	0
	Lower Snake River	714,103,694	3.2%	5.3%	0	0	0	0
	Hopkins Ridge (W184)	340,498,880	1.5%	2.5%	0	0	0	0
Total PSE Generation		**13,430,784,140**	**60.2%**	**100.0%**	**7,367,614.18**	**571**	**81**	**7,405,952**
PURCHASES [1]								
FIRM CONTRACT PURCHASES								
	POWER COST	**6,597,362,483**	**29.6%**	**100.0%**	**3,753,822**	**409**	**59**	**3,781,773**
Biogas	Bio Energy Washington (BEW)	8,127	0.0%	0.0%	0	0	0	0
Biogas	Blocks Dairy Farm	69,374	0.0%	0.0%	0	0	0	0
Biogas	Edaleen Dairy LLC	3,546,098	0.0%	0.1%	0	0	0	0
Biogas	Emerald City Renewables	31,113,473	0.1%	0.5%	0	0	0	0
Biogas	Farm Power Lynden LLC	4,062,419	0.0%	0.1%	0	0	0	0
Biogas	Farm Power Rexville LLC	5,308,467	0.0%	0.1%	0	0	0	0
Biogas	Lake Washington -- Finn Hill	270,408	0.0%	0.0%	0	0	0	0
Biogas	Rainier Bio Gas	4,296,834	0.0%	0.1%	0	0	0	0
Biogas	Van Dyk - S Holsteins	1,559,164	0.0%	0.0%	0	0	0	0
Biogas	VanderHaak Dairy Digester	4,284,825	0.0%	0.1%	0	0	0	0
Coal	Transalta Centralia Generation LLC	3,036,992,000	13.6%	46.0%	3,369,246.64	389.49	56.65	3,395,866.83
Hydro	Black Creek Hydro Inc	8,033,432	0.0%	0.1%	0	0	0	0
Hydro	Chelan PUD - RI & RR	1,904,130,000	8.5%	28.9%	0	0	0	0
Hydro	Chelan PUD - Rock Island Syst #2	-39,120,000	-0.2%	-0.6%	0	0	0	0
Hydro	Chelan PUD - Rocky Reach	-80,741,000	-0.4%	-1.2%	0	0	0	0
Hydro	Douglas PUD - Wells Project	812,102,000	3.6%	12.3%	0	0	0	0
Hydro	Electron Hydro, LLC	143,654,046	0.6%	2.2%	0	0	0	0
Hydro	Grant PUD - Priest Rapids Project	45,806,000	0.2%	0.7%	0	0	0	0
Hydro	Koma Kulshan Associates	29,784,255	0.1%	0.5%	0	0	0	0
Hydro	Nooksack	22,782,893	0.1%	0.3%	0	0	0	0
Hydro	Skookumchuck Hydro	2,326,215	0.0%	0.0%	0	0	0	0
Hydro	Smith Creek Hydro	89,100	0.0%	0.0%	0	0	0	0
Hydro	Sygitowicz Creek	414,000	0.0%	0.0%	0	0	0	0
Hydro	Twin Falls Hydro	52,656,473	0.2%	0.8%	0	0	0	0
Hydro	Weeks Falls	9,412,790	0.0%	0.1%	0	0	0	0
Solar	CC Solar 1 and CC Solar 2	29,870	0.0%	0.0%	0	0	0	0
Solar	Ikea Solar	71,965	0.0%	0.0%	0	0	0	0

Table 7. Detailed Emissions Calculations

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Emission Source	Source (Detailed)	Energy Amount (kWh)	Total % of Total Power	% of Generation or Purchase	Total CO_2 (metric ton)	Total CH_4 (metric ton)	Total N_2O (metric ton)	Total CO_2e (metric ton)
Solar	Island Community Solar LLC	62,090	0.0%	0.0%	0	0	0	0
System	BC Hydro (Point Roberts)	20,444,766	0.1%	0.3%	8,934			8,934
System	BPA	3,500,000	0.0%	0.1%	1,530			1,530
System	Transalta Centralia Generation LLC - Bookout Source Other Adjustment	447,044,000	2.0%	6.8%	195,358			195,358
Wind	3 Bar G Wind Turbine #3 LLC	132,800	0.0%	0.0%	0	0	0	0
Wind	Klondike Wind Power III	112,955,000	0.5%	1.7%	0	0	0	0
Wind	Knudsen Wind Turbine #1	56,256	0.0%	0.0%	0	0	0	0
Wind	Swauk Wind	10,224,343	0.0%	0.2%	0	0	0	0
Losses Coal	Transmission Losses (Coal)	3,036,992,000			168,462.3	19.5	2.8	169,793.3
Market	Transmission Losses (Unspecified)	470,988,766			10,291			10,291
Total - Firm Contracts		**6,597,362,483**	**29.6%**	**100.0%**	**3,753,822.17**	**408.96**	**59.49**	**3,781,773.36**
NON-FIRM CONTRACT PURCHASES								
	POWER COST	**2,278,882,966**	**10.2%**	**100.0%**	**1,045,665**	**0**	**0**	**1,045,665**
Purchases - Secondary	Avista Corp. WWP Division	146,486,000	0.7%	6.4%	64,014			64,014
Purchases - Secondary	Black Hills Power	400,000	0.0%	0.0%	175			175
Purchases - Secondary	BP Energy Co.	977,532,000	4.4%	42.9%	427,181			427,181
Purchases - Secondary	BPA	559,626,000	2.5%	24.6%	244,557			244,557
Purchases - Secondary	BPA - NWPP Reserve Sharing Energy	40,000	0.0%	0.0%	17			17
Purchases - Secondary	British Columbia Transmission Corp	13,000	0.0%	0.0%	6			6
Purchases - Secondary	Brookfield Energy Marketing	2,500,000	0.0%	0.1%	1,093			1,093
Purchases - Secondary	California ISO	44,649,250	0.2%	2.0%	19,512			19,512
Purchases - Secondary	Chelan County PUD #1	107,113,000	0.5%	4.7%	46,808			46,808
Purchases - Secondary	Citigroup Energy Inc	1,339,295,000	6.0%	58.8%	585,272			585,272
Purchases - Secondary	Clatskanie PUD	3,014,000	0.0%	0.1%	1,317			1,317
Purchases - Secondary	Conoco, Inc.	18,025,000	0.1%	0.8%	7,877			7,877
Purchases - Secondary	CP Energy Marketing (Epcor)	20,804,000	0.1%	0.9%	9,091			9,091
Purchases - Secondary	Douglas County PUD #1	16,875,000	0.1%	0.7%	7,374			7,374
Purchases - Secondary	EDF Trading NA LLC	532,133,000	2.4%	23.4%	232,542			232,542
Purchases - Secondary	Energy Keepers Inc.	-993,000	0.0%	0.0%	-434			-434
Purchases - Secondary	Eugene Water & Electric	10,165,000	0.0%	0.4%	4,442			4,442
Purchases - Secondary	Exelon Generation Co LLC	96,790,000	0.4%	4.2%	42,297			42,297
Purchases - Secondary	Grant County PUD #2	7,000	0.0%	0.0%	3			3
Purchases - Secondary	GRIDFORCE ENERGY MANAGEMENT, LLC.	10,000	0.0%	0.0%	4			4
Purchases - Secondary	Iberdrola Renewables (PPM Energy)	370,310,000	1.7%	16.2%	161,825			161,825
Purchases - Secondary	Idaho Power Company	15,896,000	0.1%	0.7%	6,947			6,947
Purchases - Secondary	Morgan Stanley CG	326,121,000	1.5%	14.3%	142,515			142,515
Purchases - Secondary	NextEra Energy Power Marketing	3,259,000	0.0%	0.1%	1,424			1,424
Purchases - Secondary	Northwestern Energy	12,612,000	0.1%	0.6%	5,511			5,511
Purchases - Secondary	Okanogan PUD	3,262,000	0.0%	0.1%	1,425			1,425
Purchases - Secondary	Pacificorp	47,439,000	0.2%	2.1%	20,731			20,731
Purchases - Secondary	Portland General Electric	104,781,000	0.5%	4.6%	45,789			45,789
Purchases - Secondary	Powerex Corp.	212,740,000	1.0%	9.3%	92,967			92,967
Purchases - Secondary	Public Service of Colorado	163,704,000	0.7%	7.2%	71,539			71,539
Purchases - Secondary	Rainbow Energy Marketing	12,632,000	0.1%	0.6%	5,520			5,520
Purchases - Secondary	Sacramento Municipal	4,000	0.0%	0.0%	2			2
Purchases - Secondary	Seattle City Light Marketing	191,487,000	0.9%	8.4%	83,680			83,680
Purchases - Secondary	Shell Energy (Coral Pwr)	540,432,000	2.4%	23.7%	236,169			236,169
Purchases - Secondary	Snohomish County PUD #1	25,932,000	0.1%	1.1%	11,332			11,332
Purchases - Secondary	Tacoma Power	123,895,000	0.6%	5.4%	54,142			54,142
Purchases - Secondary	Tenaska Power Services Co.	834,000	0.0%	0.0%	364			364
Purchases - Secondary	The Energy Authority	742,867,000	3.3%	32.6%	324,633			324,633
Purchases - Secondary	TransAlta Energy Marketing	1,686,371,000	7.6%	74.0%	736,944			736,944
Purchases - Secondary	TransCanada Energy Sales Ltd	625,000	0.0%	0.0%	273			273
Purchases - Secondary	Turlock Irrigation District	3,400,000	0.0%	0.1%	1,486			1,486
Purchases - Secondary	Vitol Inc.	23,376,000	0.1%	1.0%	10,215			10,215
EIM Purchases	CAISO EESC Load Undistributed Costs	74,381,287	0.3%	3.3%	32,505			32,505
EIM Purchases	CAISO PRSC Undistributed Costs	-11,754,273	-0.1%	-0.5%	-5,137			-5,137
EIM Purchases	Chelan PUD - RI & RR	21,981,248	0.1%	1.0%	9,606			9,606

Table 7. Detailed Emissions Calculations

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Emission Source	Source (Detailed)	Energy Amount (kWh)	Total % of Total Power	% of Generation or Purchase	Total CO_2 (metric ton)	Total CH_4 (metric ton)	Total N_2O (metric ton)	Total CO_2e (metric ton)
EIM Purchases	Colstrip - Energy Imbalance Market	7,285,823	0.0%	0.3%	3,184			3,184
EIM Purchases	Douglas PUD - Wells Project	138,900,288	0.6%	6.1%	60,699			60,699
EIM Purchases	Encogen	20,761,954	0.1%	0.9%	9,073			9,073
EIM Purchases	Ferndale Co-Generation	38,911,127	0.2%	1.7%	17,004			17,004
EIM Purchases	Freddie #1	3,646,008	0.0%	0.2%	1,593			1,593
EIM Purchases	Fredonia - Energy Imbalance Market	12,509,213	0.1%	0.5%	5,467			5,467
EIM Purchases	Fredrickson 1 & 2	13,588,458	0.1%	0.6%	5,938			5,938
EIM Purchases	Goldendale	60,944,919	0.3%	2.7%	26,633			26,633
EIM Purchases	Grant PUD - Priest Rapids Project	826,166	0.0%	0.0%	361			361
EIM Purchases	Lower Baker	137,714	0.0%	0.0%	60			60
EIM Purchases	MID-C for Energy Imbalance Market	218,811,211	1.0%	9.6%	95,620			95,620
EIM Purchases	Mint Farm	87,756,075	0.4%	3.9%	38,349			38,349
EIM Purchases	Snoqualmie-Energy Imbalance Market	-654,312	0.0%	0.0%	-286			-286
EIM Purchases	Sumas	28,322,041	0.1%	1.2%	12,377			12,377
EIM Purchases	Upper Baker	40,616,964	0.2%	1.8%	17,750			17,750
EIM Purchases	Whitehorn 2&3	3,005,095	0.0%	0.1%	1,313			1,313
EIM Purchases	Wild Horse (W183)	84,277,608	0.4%	3.7%	36,829			36,829
Interchange - In	Avista Nichols Pump	30,836,840	0.1%	1.4%	13,476			13,476
Interchange - In	Pacific Gas & Elec - Exchange	413,000,000	1.9%	18.1%	180,481			180,481
Interchange - Out	Deviation	-437,530,680	-2.0%	-19.2%	-191,201			-191,201
Interchange - Out	Pacific Gas & Elec - Exchange	-413,000,000	-1.9%	-18.1%	-180,481			-180,481
Transmission by Others	Avista Corp. WWP Division	0	0.0%	0.0%	0			0
Transmission by Others	BPA - CA Wind Integration	0	0.0%	0.0%	0			0
Transmission by Others	BPA - NWPP Reserve Sharing Energy	0	0.0%	0.0%	0			0
Transmission by Others	BPA - PTP Transactions	0	0.0%	0.0%	0			0
Transmission by Others	BPA - SCD Hourly NF	0	0.0%	0.0%	0			0
Transmission by Others	BPA - Spin Reserv Requirement	0	0.0%	0.0%	0			0
Transmission by Others	BPA - Supp Reserv Requirement	0	0.0%	0.0%	0			0
Transmission by Others	BPA IS - Hourly Non-Firm	0	0.0%	0.0%	0			0
Transmission by Others	Brookfield Energy Marketing	0	0.0%	0.0%	0			0
Transmission by Others	Iberdrola Renewables (PPM Energy)	0	0.0%	0.0%	0			0
Transmission by Others	Idaho Power Company	0	0.0%	0.0%	0			0
Transmission by Others	Morgan Stanley CG	0	0.0%	0.0%	0			0
Transmission by Others	Northwestern Energy	0	0.0%	0.0%	0			0
Transmission by Others	Portland General Electric	0	0.0%	0.0%	0			0
Transmission by Others	Powerex Corp.	0	0.0%	0.0%	0			0
Transmission by Others	Shell Energy (Coral Pwr)	0	0.0%	0.0%	0			0
Transmission by Others	The Energy Authority	0	0.0%	0.0%	0			0
Transmission by Others	TransAlta Energy Marketing	0	0.0%	0.0%	0			0
Sales for Resale	Avista Corp. WWP Division	-72,611,000	-0.3%	-3.2%	-31,731			-31,731
Sales for Resale	Black Hills Power	-700,000	0.0%	0.0%	-306			-306
Sales for Resale	BP Energy Co.	-276,166,000	-1.2%	-12.1%	-120,685			-120,685
Sales for Resale	BPA	-710,856,000	-3.2%	-31.2%	-310,644			-310,644
Sales for Resale	BPA - NWPP Reserve Sharing Energy	-50,000	0.0%	0.0%	-22			-22
Sales for Resale	British Columbia Transmission Corp	-9,000	0.0%	0.0%	-4			-4
Sales for Resale	Brookfield Energy Marketing	-12,400,000	-0.1%	-0.5%	-5,419			-5,419
Sales for Resale	California ISO	-10,000	0.0%	0.0%	-4			-4
Sales for Resale	Chelan County PUD #1	-28,448,000	-0.1%	-1.2%	-12,432			-12,432
Sales for Resale	Citigroup Energy Inc	-508,700,000	-2.3%	-22.3%	-222,302			-222,302
Sales for Resale	Clatskanie PUD	-50,086,000	-0.2%	-2.2%	-21,888			-21,888
Sales for Resale	Conoco, Inc.	-95,250,000	-0.4%	-4.2%	-41,624			-41,624
Sales for Resale	CP Energy Marketing (Epcor)	-690,000	0.0%	0.0%	-302			-302
Sales for Resale	Douglas County PUD #1	-9,233,000	0.0%	-0.4%	-4,035			-4,035
Sales for Resale	EDF Trading NA LLC	-23,603,000	-0.1%	-1.0%	-10,315			-10,315
Sales for Resale	Energy Keepers Inc.	-3,000	0.0%	0.0%	-1			-1
Sales for Resale	Eugene Water & Electric	-97,275,000	-0.4%	-4.3%	-42,509			-42,509
Sales for Resale	Exelon Generation Co LLC	-115,827,000	-0.5%	-5.1%	-50,616			-50,616
Sales for Resale	Grant County PUD #2	-5,000	0.0%	0.0%	-2			-2
Sales for Resale	GRIDFORCE ENERGY MANAGEMENT, LLC.	-585,000	0.0%	0.0%	-256			-256
Sales for Resale	Iberdrola Renewables (PPM Energy)	-447,031,000	-2.0%	-19.6%	-195,353			-195,353
Sales for Resale	Idaho Power Company	-36,409,000	-0.2%	-1.6%	-15,911			-15,911
Sales for Resale	Morgan Stanley CG	-770,023,000	-3.5%	-33.8%	-336,500			-336,500
Sales for Resale	Natur Ener USA	-227,000	0.0%	0.0%	-99			-99
Sales for Resale	Nevada Power Company	-11,000	0.0%	0.0%	-5			-5
Sales for Resale	NextEra Energy Power Marketing	-5,000,000	0.0%	-0.2%	-2,185			-2,185
Sales for Resale	Northwestern Energy	-14,024,000	-0.1%	-0.6%	-6,128			-6,128
Sales for Resale	Okanogan PUD	-1,430,000	0.0%	-0.1%	-625			-625

Table 7. Detailed Emissions Calculations

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Emission Source	Source (Detailed)	Energy Amount (kWh)	Total % of Total Power	% of Generation or Purchase	Total CO_2 (metric ton)	Total CH_4 (metric ton)	Total N_2O (metric ton)	Total CO_2e (metric ton)
Sales for Resale	Pacificorp	-102,727,000	-0.5%	-4.5%	-44,892			-44,892
Sales for Resale	Portland General Electric	-144,507,000	-0.6%	-6.3%	-63,150			-63,150
Sales for Resale	Powerex Corp.	-848,671,000	-3.8%	-37.2%	-370,869			-370,869
Sales for Resale	Public Service of Colorado	-24,600,000	-0.1%	-1.1%	-10,750			-10,750
Sales for Resale	Rainbow Energy Marketing	-640,000	0.0%	0.0%	-280			-280
Sales for Resale	Sacramento Municipal	-30,000	0.0%	0.0%	-13			-13
Sales for Resale	Seattle City Light Marketing	-118,028,000	-0.5%	-5.2%	-51,578			-51,578
Sales for Resale	Shell Energy (Coral Pwr)	-267,046,000	-1.2%	-11.7%	-116,699			-116,699
Sales for Resale	Snohomish County PUD #1	-32,585,000	-0.1%	-1.4%	-14,240			-14,240
Sales for Resale	Tacoma Power	-35,224,000	-0.2%	-1.5%	-15,393			-15,393
Sales for Resale	The Energy Authority	-433,561,000	-1.9%	-19.0%	-189,466			-189,466
Sales for Resale	TransAlta Energy Marketing	-612,673,000	-2.7%	-26.9%	-267,738			-267,738
Sales for Resale	TransCanada Energy Sales Ltd	-32,734,000	-0.1%	-1.4%	-14,305			-14,305
Sales for Resale	Turlock Irrigation District	-1,212,000	0.0%	-0.1%	-530			-530
Sales for Resale	Vitol Inc.	-24,800,000	-0.1%	-1.1%	-10,838			-10,838
Sales for Resale	Western Area Power Association	-3,000	0.0%	0.0%	-1			-1
Sales for Resale	Williams Power Company	-3,180,000	0.0%	-0.1%	-1,390			-1,390
EIM Sales	CAISO PRSC Undistributed Costs	-900,089	0.0%	0.0%	-393			-393
EIM Sales	Chelan PUD - RI & RR	-27,002,568	-0.1%	-1.2%	-11,800			-11,800
EIM Sales	Douglas PUD - Wells Project	-96,551,426	-0.4%	-4.2%	-42,193			-42,193
EIM Sales	Encogen	-34,797,416	-0.2%	-1.5%	-15,206			-15,206
EIM Sales	Ferndale Co-Generation	-62,188,292	-0.3%	-2.7%	-27,176			-27,176
EIM Sales	Fredonia - Energy Imbalance Market	-9,306,464	0.0%	-0.4%	-4,067			-4,067
EIM Sales	Fredrickson 1 & 2	-14,699,373	-0.1%	-0.6%	-6,424			-6,424
EIM Sales	Goldendale	-56,080,087	-0.3%	-2.5%	-24,507			-24,507
EIM Sales	Grant PUD - Priest Rapids Project	-2,127,880	0.0%	-0.1%	-930			-930
EIM Sales	MID-C for Energy Imbalance Market	-194,203,115	-0.9%	-8.5%	-84,867			-84,867
EIM Sales	Mint Farm	-49,821,656	-0.2%	-2.2%	-21,772			-21,772
EIM Sales	Sumas	-21,191,986	-0.1%	-0.9%	-9,261			-9,261
EIM Sales	Upper Baker	-6,868,940	0.0%	-0.3%	-3,002			-3,002
EIM Sales	Whitehorn 2&3	-3,020,005	0.0%	-0.1%	-1,320			-1,320
EIM Sales	Wild Horse (W183)	-107,498,761	-0.5%	-4.7%	-46,977			-46,977
Market	Transmission Losses (Unspecified)	2,278,882,966			49,794			49,794
Total Non-Firm Contract Purchases		**2,278,882,966**	**10%**	**100%**	**1,045,665.449**	**0.000**	**0.000**	**1,045,665.449**
Total Firm & Non-Firm Contracts Purchases		**8,876,245,449**			**4,799,488**	**409**	**59**	**4,827,439**
Total Firm & Non-Firm Contracts Purchases & PSE Generated		**22,307,029,589**	**100%**		**12,167,101.8**	**980**	**140**	**12,233,391**

Data Source:
[1] Annual Power Cost Summary Report (PSE)
[2] Colstrip Operating Statistics (Colstrip)

Note(s):
(1) Non-firm contract purchases do not include "Book Outs" under Emerging Issues Task Force Issue No. 03-11. "Book outs" are included in Sales to Other Utilities and Marketers.
(2) Emissions from non-firm contract purchases calculated via national/ regional emission factors. See Table A-3.
(3) PSE-Generated gas turbines track diesel fuel emissions under natural gas emissions.

Table 8. Total Emissions by Source

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Emission Source	Energy			Emissions								Emission Intensity			
	Amount	(UOM)	(%) [1]	CO_2		CH_4		N_2O		SF_6		CO_2 (UOM)	CH_4 (UOM)	N_2O (UOM)	SF_6 (UOM)
				(metric ton)	(%) [2]	(metric ton)	(%) [2]	(metric ton)	(%) [2]	(metric ton)	(%) [2]				
Generated and Purchased Electricity															
PSE-Owned Electric Operations															
Hydro	712,727,200	kWh	3.2%	0	0%	0	0%	0	0%	0	0%	0.000 lb/kWh	0E+00 lb/kWh	0E+00 lb/kWh	0.0 lb/kWh
Coal	4,251,239,000	kWh	19.1%	4,496,229	26.0%	520	15.1%	76	53.9%	0	0%	2.332 lb/kWh	2.7E-04 lb/kWh	3.9E-05 lb/kWh	0.0 lb/kWh
Natural Gas/ Oil	6,799,329,148	kWh	30.5%	2,871,386	16.6%	51	1.5%	5	3.6%	0	0%	0.931 lb/kWh	1.7E-05 lb/kWh	1.7E-06 lb/kWh	0.0 lb/kWh
Wind	1,667,488,792	kWh	7.5%	0	0%	0	0%	0	0%	0	0%	0.000 lb/kWh	0E+00 lb/kWh	0E+00 lb/kWh	0.0 lb/kWh
Electrical Transmission and Distribution Equipment	0	kWh	0%	0	0%	0	0%	0	0%	0.01	100%	NC	NC	NC	NC
Total - PSE-owned Electric Operations	**13,430,784,140**	**kWh**	**60.2%**	**7,367,614**	**42.6%**	**571**	**16.6%**	**81**	**57.6%**	**0.01**	**100%**	**1.209 lb/kWh**	**9.4E-05 lb/kWh**	**1.3E-05 lb/kWh**	**NC lb/kWh**
Firm & Non-Firm Contracts Purchases															
Firm Contracts [3]	6,597,362,483	kWh	29.6%	3,753,822	21.7%	409	11.9%	59	42.4%	0	0%	1.254 lb/kWh	1.4E-04 lb/kWh	2.0E-05 lb/kWh	0.0 lb/kWh
Non-Firm Contracts [1][3]	2,278,882,966	kWh	10.2%	1,045,665	6.1%	0	0.0%	0	0.0%	0	0%	1.012 lb/kWh	0E+00 lb/kWh	0E+00 lb/kWh	0.0 lb/kWh
Total - Firm & Non-Firm Contracts Purchases	**8,876,245,449**	**kWh**	**39.8%**	**4,799,488**	**27.8%**	**409**	**11.9%**	**59**	**42.4%**	**0**	**0%**	**1.192 lb/kWh**	**1.0E-04 lb/kWh**	**1.5E-05 lb/kWh**	**NC lb/kWh**
Total - Generated and Purchased Electricity	**22,307,029,589**	**kWh**	**100%**	**12,167,102**	**70.4%**	**980**	**28.5%**	**140**	**100%**	**0.01**	**100%**	**1.202 lb/kWh**	**9.7E-05 lb/kWh**	**1.4E-05 lb/kWh**	**1.1E-09 lb/kWh**
Natural Gas Operations															
Distribution and Storage of PSE-owned Natural Gas Operations															
Distribution	117,866,839	thm	100%	74	0.0004%	2,453	71.5%	0	0%	0	0%	0.001 lb/thm	0.046 lb/thm	0.0E+00 lb/thm	0 lb/thm
Total - Natural Gas Operations	**117,866,839**	**thm**	**100%**	**74**	**0.0004%**	**2,453**	**71.5%**	**0**	**0%**	**0**	**0%**	**0.001 lb/thm**	**0.046 lb/thm**	**0.0E+00 lb/thm**	**0 lb/thm**
Natural Gas Supply															
Supply to End-Users	940,406,665	thm	100%	5,115,812	29.6%	0	0%	0	0%	0	0%	12.0 lb/thm	0.0 lb/thm	0.0 lb/thm	0 lb/thm
Total - Natural Gas Supply	**940,406,665**	**thm**	**100%**	**5,115,812**	**29.6%**	**0**	**0%**	**0**	**0%**	**0**	**0%**	**12.0 lb/thm**	**0.0 lb/thm**	**0.0 lb/thm**	**0 lb/thm**
Emissions from All Sources				**17,282,988**	**100%**	**3,433**	**100%**	**140**	**100%**	**0.01**	**100%**				

Note(s):

(1) Percentage of energy within source category
(2) Percentage of emissions within source category
(3) Includes transmission losses
(4) NC = Not calculated

Table 9. Total Emissions by Source in CO2 Equivalents (CO2e)

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Emission Source	Energy			Emissions in CO_2 Equivalents (CO_2e) - 100-Year Timeframe (Tons)										Emission Intensity	
	Amount	(UOM)	(%) [1]	CO_2		CH_4		N_2O		SF_6		Total		Total	(UOM)
				(metric ton)	(%) [2]	(metric ton)	(%) [2]	(metric ton)	(%) [2]	(metric ton)	(%) [2]	(metric ton)	(%) [2]		
Generated and Purchased Electricity															
PSE-Owned Electric Operations															
Hydro	712,727,200	kWh	3.2%	0	0%	0	0%	0	0%	0	0%	0.0	0.0%	0	lb/kWh
Coal	4,251,239,000	kWh	19.1%	4,496,229	25.8%	13,000	0.1%	22,543	0.1%	0	0%	4,531,772.0	26.0%	2.350	lb/kWh
Natural Gas/ Oil	6,799,329,148	kWh	30.5%	2,871,386	16.5%	1,274	0.007%	1,520	0.01%	0	0%	2,874,180.2	16.5%	0.932	lb/kWh
Wind	1,667,488,792	kWh	7.5%	0	0%	0	0%	0	0%	0	0%	0.0	0.0%	0	lb/kWh
Electrical Transmission and Distribution Equipment	0	kWh	0%	0	0%	0	0%	0	0%	265	0.00%	265	0.002%	NC	
Total - PSE-owned Electric Operations	**13,430,784,140**	**kWh**	**60%**	**7,367,614**	**42.3%**	**14,275**	**0.1%**	**24,063**	**0.1%**	**265**	**0.00%**	**7,406,217.0**	**42.5%**	**1.216**	**lb/kWh**
Firm & Non-Firm Contracts Purchases															
Firm Contracts[3]	6,597,362,483	kWh	29.6%	3,753,822	21.6%	10,224	0.059%	17,727	0.10%	0	0%	3,781,773.4	21.7%	1.264	lb/kWh
Non-Firm Contracts [1][3]	2,278,882,966	kWh	10.2%	1,045,665	6.0%	0	0.00%	0	0.0%	0	0%	1,045,665.4	6.0%	1.012	lb/kWh
Total - Firm & Non-Firm Contracts Purchases	**8,876,245,449**	**kWh**	**39.8%**	**4,799,488**	**27.6%**	**10,224**	**0.1%**	**17,727**	**0.1%**	**0**	**0%**	**4,827,438.8**	**27.7%**	**1.199**	**lb/kWh**
Total - Generated and Purchased Electricity	**22,307,029,589**	**kWh**	**100%**	**12,167,102**	**69.9%**	**24,499**	**0.1%**	**41,791**	**0.2%**	**265**	**0.00%**	**12,233,655.8**	**70.3%**	**1.209**	**lb/kWh**
Natural Gas Operations															
Distribution and Storage of PSE-owned Natural Gas Operations															
Distribution	117,866,839	thm	100%	74	0.000%	61,331	0.4%	0	0%	0	0%	61,404.9	0.4%	1.1	lb/thm
												0.0	0.0%		
Total - Natural Gas Operations	**117,866,839**	**thm**	**100%**	**74**	**0.000%**	**61,331**	**0.4%**	**0**	**0%**	**0**	**0%**	**61,404.9**	**0.353%**	**1.1**	**lb/thm**
Natural Gas Supply															
Supply to End-Users	940,406,665	thm	100%	5,115,812	29.4%	0	0%	0	0%	0	0%	5,115,812	29.4%	12	lb/thm
Total - Natural Gas Supply	**940,406,665**	**thm**	**100%**	**5,115,812**	**29.4%**	**0**	**0%**	**0**	**0%**	**0**	**0%**	**5,115,812**	**29.4%**	**12**	**lb/thm**
Emissions from All Sources				**17,282,988**	**99.3%**	**85,830**	**0.5%**	**41,791**	**0.2%**	**265**	**0.00%**	**17,410,873**	**100%**	**NC**	

Data Source:
[1] EPA GHG MRR Subpart A (40 CFR 98), Table A-1

Note(s):
(1) Percentage of energy within source categories.
(2) Percentage of total CO2e among all sources.
(3) Includes transmission losses
(4) NC = Not calculated

Global Warming Potentials [1]:

Time Horizon	CO_2	CH_4	N_2O	SF_6
100 years	1	25	298	22,800

Table A-1. Emissions from PSE-Owned Electric Operations: Colstrip

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Unit ID	Unit Type [1]	Capacity [1] (MW)	PSE Share [1]	Fuel Type [2]	HI [(2),[3]]	(UOM)	PSE Share of Emissions (4): CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)
Colstrip Unit 1	Coal	307	50%	Coal	19,415,318	MMBtu	923,568 {1}	106.86 {2}	15.55 {2}
				Fuel Oil	51,159	MMBtu			
Colstrip Unit 2	Coal	307	50%	Coal	20,709,549	MMBtu	984,966 {1}	113.93 {2}	16.57 {2}
				Fuel Oil	18,282	MMBtu			
Colstrip Unit 3	Coal	370	25%	Coal	55,260,212	MMBtu	1,314,441 {1}	151.99 {2}	22.11 {2}
				Fuel Oil	37,853	MMBtu			
Colstrip Unit 4	Coal	370	25%	Coal	53,528,688	MMBtu	1,273,254 {1}	147.23 {2}	21.42 {2}
				Fuel Oil	38,451	MMBtu			
					Total		**4,496,229**	**520.0**	**75.6**

Emission Factors:

Fuel Type	CH_4 (kg/MMBtu)	N_2O (kg/MMBtu)	HHV (MMBtu/gal)
Coal	1.1E-02 [4]	1.6E-03 [4]	[redacted]
Propane	3.0E-03 [4]	6.0E-04 [4]	[redacted]
Distillate Fuel Oil	3.0E-03 [4]	6.0E-04 [4]	0.139

Calculation Methodology:
{1} EPA GHG MRR Subpart C (40 CFR 98.33) Tier 4
{2} EPA GHG MRR Subpart C (40 CFR 98.33) Tier 4 (Eq. C-10)

Data Source:
[1] Puget Sound Energy Form 10-K
[2] Colstrip Operating Data
[3] Colstrip Operating Statistics
[4] EPA GHG MRR Subpart C (40 CFR 98), Table C-2

Note(s):
(1) HHV = High heating value
(2) HI = Cumulative annual heat input
(3) Reserved
(4) Calculated according to PSE's owned portion of the facility using equity share method

Table A-2. Emissions from PSE-Owned Electric Operations: Natural Gas/ Petroleum

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Unit ID	Unit Type [1]	Capacity [1] (MW)	PSE Share [1]	Fuel Type [2]	Fuel Usage [2]	(UOM)	HHV [2],[4],(1)	(UOM)	HI (2),[3]	(UOM)	PSE Share of Emissions (4): CO_2 (metric ton)		CH_4 (metric ton)		N_2O (metric ton)	
Crystal Mountain	Internal Combustion	3	100%	Distillate Fuel Oil No. 2	15,077	gal	0.138	MMBtu/gal	NR (3)		154.11	{3}	0.006	{5}	0.0013	{5}
Encogen 1	Natural gas cogeneration	165	100%	Natural Gas					1,185,545	MMBtu	63,915.80	{1}, [3]	1.19	{2}	0.12	{2}
Encogen 2	Natural gas cogeneration			Natural Gas					1,151,373	MMBtu	62,070.37	{1}, [3]	1.15	{2}	0.12	{2}
Encogen 3	Natural gas cogeneration			Natural Gas					1,215,390	MMBtu	65,527.10	{1}, [3]	1.22	{2}	0.12	{2}
Ferndale 1	Natural gas combined cycle	253	100%	Natural Gas					4,415,730	MMBtu	238,067.35	{1}, [3]	4.42	{2}	0.44	{2}
Ferndale 2	Natural gas combined cycle			Natural Gas					4,446,354	MMBtu	239,721.58	{1}, [3]	4.45	{2}	0.44	{2}
Frederickson Unit 1	Natural gas combined cycle	136	49.85%	Natural Gas					4,752,450	MMBtu	256,217.91	{1}, [3]	2.37	{2}	0.24	{2}
Fredonia 1	Dual-fuel combustion turbines	207	100%	Natural Gas	709,380,000	scf	0.001102	MMBtu/scf	781,737	MMBtu	41,478.95	{3}	0.78	{5}	0.08	{5}
				Distillate Fuel Oil No. 2	24,000.0	gal	0.139	MMBtu/gal	3,334	MMBtu	246.62	{3}	0.01	{5}	0.002	{5}
											41,725.57		0.79		0.08	
Fredonia 2	Dual-fuel combustion turbines			Natural Gas	1,620,109,000	scf	0.001099	MMBtu/scf	1,780,500	MMBtu	94,473.32	{3}	1.78	{5}	0.18	{5}
				Distillate Fuel Oil No. 2	4,093	gal	0.139	MMBtu/gal	569	MMBtu	42.06	{3}	0.00	{5}	0.000	{5}
											94,515.38		1.78		0.18	
Fredonia 3	Dual-fuel combustion turbines	107	100%	Natural Gas					36,261	MMBtu	1,705.87	{1}, [3]	0.04	{2}	0.00	{2}
Fredonia 4	Dual-fuel combustion turbines			Natural Gas					303,996	MMBtu	16,436.88	{1}, [3]	0.30	{2}	0.03	{2}
Frederickson 1	Dual-fuel combustion turbines	149	100%	Natural Gas	683,593,000	scf	0.001098	MMBtu/scf	750,585	MMBtu	39,826.05	{3}	0.75	{5}	0.08	{5}
				Distillate Fuel Oil No. 2	18,228	gal	0.139033	MMBtu/gal	2,534	MMBtu	187.44	{3}	0.0076	{5}	0.0015	{5}
											40,013.48		0.76		0.08	
Frederickson 2	Dual-fuel combustion turbines			Natural Gas	514,457,000	scf	0.001097	MMBtu/scf	564,359	MMBtu	29,944.91	{3}	0.56	{5}	0.06	{5}
				Distillate Fuel Oil No. 2	0	gal	0.139078	MMBtu/gal	0	MMBtu	0.00	{3}	0.00	{5}	0.000	{5}
											29,944.91		0.56		0.06	
Goldendale	Natural gas combined cycle	315	100%	Natural Gas					13,510,385	MMBtu	728,382.59	{1}, [3]	13.51	{2}	1.35	{2}
Mint Farm	Natural gas combined cycle	297	100%	Natural Gas					14,072,251	MMBtu	758,675.98	{1}, [3]	14.07	{2}	1.41	{2}
Sumas	Natural gas cogeneration	127	100%	Natural Gas					4,219,415	MMBtu	227,480.66	{1}, [3]	4.22	{2}	0.42	{2}
Whitehorn 2	Dual-fuel combustion turbines	149	100%	Natural Gas	62,151,000	scf	0.001101	MMBtu/scf	68,428	MMBtu	3,630.80	{3}	0.07	{5}	0.01	{5}
				Distillate Fuel Oil No. 2	3,912	gal	0.139096	MMBtu/gal	544	MMBtu	40.24	{3}	0.00	{5}	0.000	{5}
											3,671.05		0.07		0.01	
Whitehorn 3	Dual-fuel combustion turbines			Natural Gas	45,103,000	scf	0.0011	MMBtu/scf	49,613	MMBtu	2,632.48	{3}	0.05	{5}	0.00	{5}
				Distillate Fuel Oil No. 2	51,188	gal	0.139096	MMBtu/gal	7,120	MMBtu	526.60	{3}	0.02	{5}	0.004	{5}
											3,159.08		0.07		0.01	
									Total		**2,871,385.7**		**51.0**		**5.1**	

Table A-2. Emissions from PSE-Owned Electric Operations: Natural Gas/ Petroleum

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Emission Factors:

Fuel Type	CO_2 (kg/MMBtu)		CH_4 (kg/MMBtu)		N_2O (kg/MMBtu)		HHV (1) (MMBtu/scf or MMBtu/gal)	
Natural Gas	53.06	[4]	1.0E-03	[4]	1.0E-04	[4]	1.026E-03	[4]
Distillate Fuel Oil No. 2	73.96	[4]	3.0E-03	[4]	6.0E-04	[4]	0.139	[4]

Calculation Methodology:

{1} EPA GHG MRR Subpart C (40 CFR 98.33) Tier 4
{2} EPA GHG MRR Subpart C (40 CFR 98.33) Tier 4 (Eq. C-10)
{3} EPA GHG MRR Subpart C (40 CFR 98.33) Tier 2 (Eq. C-2a)
{4} EPA GHG MRR Subpart C (40 CFR 98.33) Tier 2 (Eq. C-2b)
{5} EPA GHG MRR Subpart C (40 CFR 98.33) Tier 2 (Eq. C-9a)

Data Source:

[1] Puget Energy Form 10-K
[2] PSE Subpart C Thermal Worksheets
[3] ECMPS Feedback (EPA)
[4] EPA GHG MRR Subpart C (40 CFR 98), Table C-1 & Table C-2

Note(s):

(1) HHV = High heating value. HHV for oil is sampled on every oil delivery. An HHV report is provided by the natural gas suppliers monthly representing daily and monthly HHV values.
(2) HI = Cumulative annual heat input
(3) NR = Not required for calculations
(4) Calculated according to PSE's owned portion of the facility using equity share method

Table A-3. Emission Factors for Firm & Non-Firm Contracts Purchased Electricity

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Fuel Type	Heat Rate [8]	Emission Rate			Emission Rate [6]		
		CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
	(Btu/kWh)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/kWh)	(lb/kWh)	(lb/kWh)
Coal (1)	**8,800**				**2.095** [5]	**1.241E-05** [7]	**2.869E-05** [7]
Natural Gas (2),(5)					**1.321** [5]	**3.626E-05** [7]	**1.325E-05** [7]
Hydro	**0**	**0**	**0**	**0**	**0** [7]	**0** [7]	**0** [7]
Wind	**0**	**0**	**0**	**0**	**0** [7]	**0** [7]	**0** [7]
Nuclear	**0**	**0**	**0**	**0**	**0** [7]	**0** [7]	**0** [7]
Biomass (3)	**13,500**	**195** [4]	**0.021** [4]	**0.013** [4]	**2.633** [7]	**2.835E-04** [7]	**1.755E-04** [7]
Petroleum (4)	**9,960**	**161.27** [1]	**0.00163** [2]	**0.0014** [2]	**1.969** [5]	**1.623E-05** [2]	**1.394E-05** [2]
Other					**0.963** [6]	**1.110E-05** [2]	**1.920E-05** [2]

Data Source:
[1] Voluntary Reporting of Greenhouse Gases Program – Fuel and Energy Source Codes and Emission Coefficients (DOE/EIA 2011)
[2] Updated State-level Greenhouse Gas Emission Coefficients for Electricity Generation 1998-2000, Table 1 & Table 3 (DOE/EIA, April 2002)
[3] AP-42 Ch 3, Table 3.1-2a (EPA April 2000)
[4] AP-42 Ch 1, Table 1.6-3 (EPA September 2003)
[5] Carbon Dioxide Emissions from the Generation of Electric Power in the United States, Table 4 (DOE/EPA July 2000)
[6] Unspecified Emission Rate (SB 5116, May 7, 2019)
[7] Calculated values
[8] Assumptions to the Annual Energy Outlook 2017, Table 8.2 (DOE/EIA January 2018); https://www.eia.gov/outlooks/aeo/assumptions/pdf/0554(2017)

Note(s):
(1) Assume same heat rate for all coal types, uses heat rate for scrubbed coal
(2) Assume same emission rate for SCGT and CCGT
(3) Assume wood waste from a mill
(4) Assume SCGT running on No. 2 Diesel fuel type
(5) CCGT = Combined Cycle Gas Turbine; SCGT = Semi-Closed Gas Turbine
(6) Calculated using heat rate and emission rate in lb/MMBtu. Emission rate for coal is the average of the listed coal types. Emission rate for natural gas is the average of the listed natural gas types.

Table A-4. Global Warming Potentials

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Global Warming Potentials used in the 2006 GHG inventory [1]:

Time Horizon	CO_2	CH_4	N_2O	SF_6
500 years	1	7.6	153	32,600
100 years	1	25	298	22,800
20 years	1	72	289	16,300

Global Warming Potentials used in the 2007 and 2008 GHG inventories [2]:

Time Horizon	CO_2	CH_4	N_2O	SF_6
500 years	1	7	275	32,400
100 years	1	23	296	22,200
20 years	1	62	156	15,100

Global Warming Potentials used in the 2009 - 2012 GHG inventories [3]:

Time Horizon	CO_2	CH_4	N_2O	SF_6
100 years	1	21	310	23,900

Global Warming Potentials used in the 2013-2018 GHG inventories [4]:

Time Horizon	CO_2	CH_4	N_2O	SF_6
100 years	1	25	298	22,800

Data Source:
[1] IPCC Fourth Assessment Report: Climate Change 2007, Working Group I: The Physical Science Basis, Table 2.14 (IPCC 2007)
[2] IPCC Third Assessment Report: Climate Change 2001, Synthesis Report, Work Group I - Technical Summary, Table 3 (IPCC 200
[3] EPA GHG MRR Subpart A (40 CFR 98.9), Table A-1 (EPA 2012)
[4] EPA GHG MRR Subpart A (40 CFR 98.9), Table A-1 (EPA 2015)

Table B-1. EPA GHG MRR Subpart A - General Provisions

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
98.3(c)(1)	Facility name or supplier name (as appropriate), and physical street address of the facility or supplier, including the city, state, and zip code.	Puget Sound Energy.
98.3(c)(2)	Year and months covered by the report.	January - December, 2016.
98.3(c)(3)	Date of submittal.	By March 31, 2017.
98.3(c)(4)	For facilities, except as otherwise provided in paragraph (c)(12) of this section, report annual emissions of CO_2, CH_4, N_2O, each fluorinated GHG (as defined in §98.6), and each fluorinated heat transfer fluid (as defined in § 98.98) as follows:	See response in the following subsections.
98.3(c)(4)(i)	Annual emissions (excluding biogenic CO_2) aggregated for all GHG from all applicable source categories, expressed in metric tons of CO_2e calculated using Equation A-1 of this subpart. For electronics manufacturing (as defined in § 98.90), starting in reporting year 2012 the CO_2e calculation must include each fluorinated heat transfer fluid (as defined in § 98.98) whether or not it is also a fluorinated GHG.	See Tables B-7 through B-10.
98.3(c)(4)(ii)	Annual emissions of biogenic CO_2 aggregated for all applicable source categories, expressed in metric tons.	NA - There was no source of biogenic CO_2 emissions.
98.3(c)(4)(iii)	Annual emissions from each applicable source category, expressed in metric tons of each applicable GHG listed in paragraphs (c)(4)(iii)(A) through (c)(4)(iii)(E) of this section.	See response in the following subsections.
98.3(c)(4)(iii)(A)	Biogenic CO_2.	NA - There was no source of biogenic CO_2 emissions.
98.3(c)(4)(iii)(B)	CO_2 (excluding biogenic CO_2).	See Tables B-7 through B-10.
98.3(c)(4)(iii)(C)	CH_4.	See Tables B-7 through B-10.
98.3(c)(4)(iii)(D)	N_2O.	See Tables B-7 through B-10.
98.3(c)(4)(iii)(E)	Each fluorinated GHG (as defined in §98.6), except fluorinated gas production facilities must comply with §98.126(a) rather than this paragraph (c)(4)(iii)(E). If a fluorinated GHG does not have a chemical-specific GWP in Table A-1 of this subpart, identify and report the fluorinated GHG group of which that fluorinated GHG is a member.	See Tables B-7 through B-10.
98.3(c)(4)(iii)(F)	For electronics manufacturing (as defined in §98.90), each fluorinated heat transfer fluid (as defined in §98.98) that is not also a fluorinated GHG as specified under (c)(4)(iii)(E) of this section. If a fluorinated heat transfer fluid does not have a chemical-specific GWP in Table A-1 of this subpart, identify and report the fluorinated GHG group of which that fluorinated heat transfer fluid is a member.	NA - Facility does not belong to electronics manufacturing source category.
98.3(c)(4)(iv)	Except as provided in paragraph (c)(4)(vii) of this section, emissions and other data for individual units, processes, activities, and operations as specified in the “Data reporting requirements” section of each applicable subpart of this part.	See Tables B-7 through B-10.
98.3(c)(4)(v)	Indicate (yes or no) whether reported emissions include emissions from a cogeneration unit located at the facility.	See Tables B-7 through B-10.
98.3(c)(4)(vi)	[Reserved]	No response required.
98.3(c)(4)(vii)	The owner or operator of a facility is not required to report the data elements specified in Table A-6 of this subpart for calendar year 2010 through 2011 until March 31, 2013. The owner or operator of a facility is not required to report the data elements specified in Table A-7 to this subpart for calendar years 2010 through 2013 until March 31, 2015 (as part of the annual report for reporting year 2014), except as otherwise specified in Table A-7 of this subpart.	No response required.
98.3(c)(4)(viii)	Applicable source categories means stationary fuel combustion sources (subpart C of this part), miscellaneous use of carbonates (subpart U of this part), and all of the source categories listed in Table A-3 and Table A-4 of this subpart present at the facility.	See Tables B-7 through B-10.
98.3(c)(5)	For suppliers, report annual quantities of CO_2, CH_4, N_2O, and each fluorinated GHG (as defined in §98.6) that would be emitted from combustion or use of the products supplied, imported, and exported during the year. Calculate and report quantities at the following levels:	See response in the following subsections.
98.3(c)(5)(i)	Total quantity of GHG aggregated for all GHG from all applicable supply categories in Table A-5 of this subpart and expressed in metric tons of CO_2e calculated using Equation A-1 of this subpart.	See Tables B-7 through B-10.
98.3(c)(5)(ii)	Quantity of each GHG from each applicable supply category in Table A-5 to this subpart, expressed in metric tons of each GHG.	See Tables B-7 through B-10.
98.3(c)(5)(iii)	Any other data specified in the “Data reporting requirements” section of each applicable subpart of this part.	See Tables B-7 through B-10.
98.3(c)(6)	A written explanation, as required under §98.3(e), if you change emission calculation methodologies during the reporting period.	Calculation methodology was consistent during the reporting period.
98.3(c)(7)	A brief description of each “best available monitoring method” used, the parameter measured using the method, and the time period during which the “best available monitoring method” was used, if applicable.	To be addressed by PSE.
98.3(c)(8)	Each data element for which a missing data procedure was used according to the procedures of an applicable subpart and the total number of hours in the year that a missing data procedure was used for each data element.	To be addressed by PSE.
98.3(c)(9)	A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of §98.4(e)(1).	To be addressed by PSE.
98.3(c)(10)	NAICS code(s) that apply to the facility or supplier.	See response in the following subsections.
98.3(c)(10)(i)	Primary NAICS code. Report the NAICS code that most accurately describes the facility or supplier's primary product/activity/service. The primary product/activity/service is the principal source of revenue for the facility or supplier. A facility or supplier that has two distinct products/activities/services providing comparable revenue may report a second primary NAICS code.	221112 Fossil Fuel Electric Power Generation, 221210 Natural Gas Distribution.
98.3(c)(10)(ii)	Additional NAICS code(s). Report all additional NAICS codes that describe all product(s)/activity(s)/service(s) at the facility or supplier that are not related to the principal source of revenue.	NA - No additional NAICS codes.
98.3(c)(11)	Legal name(s) and physical address(es) of the highest-level United States parent company(s) of the owners (or operators) of the facility or supplier and the percentage of ownership interest for each listed parent company as of December 31 of the year for which data are being reported according to the following instructions:	See response in the following subsections.
98.3(c)(11)(i)	If the facility or supplier is entirely owned by a single United States company that is not owned by another company, provide that company's legal name and physical address as the United States parent company and report 100 percent ownership.	PSE reports GHG for facilities that it wholly or partially owns. PSE's share of each facility is provided in Table B-7. The following is PSE's legal name and physical address: Puget Sound Energy, Inc. 10885 NE 4th Street, Suite 1200, Bellevue, Washington 98004-5591.
98.3(c)(11)(ii)	If the facility or supplier is entirely owned by a single United States company that is, itself, owned by another company (e.g., it is a division or subsidiary of a higher-level company), provide the legal name and physical address of the highest-level company in the ownership hierarchy as the United States parent company and report 100 percent ownership.	PSE reports GHG for facilities that it wholly or partially owns. PSE's share of each facility is provided in Table B-7. PSE is the parent company.

Table B-1. EPA GHG MRR Subpart A - General Provisions

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
98.3(c)(11)(iii)	If the facility or supplier is owned by more than one United States company (e.g., company A owns 40 percent, company B owns 35 percent, and company C owns 25 percent), provide the legal names and physical addresses of all the highest-level companies with an ownership interest as the United States parent companies, and report the percent ownership of each company.	PSE reports GHG for facilities that it wholly or partially owns. PSE's share of each facility is provided in Table B-7. The following is PSE's legal name and physical address: Puget Sound Energy, Inc. 10885 NE 4th Street, Suite 1200, Bellevue, Washington 98004-5591.
98.3(c)(11)(iv)	If the facility or supplier is owned by a joint venture or a cooperative, the joint venture or cooperative is its own United States parent company. Provide the legal name and physical address of the joint venture or cooperative as the United States parent company, and report 100 percent ownership by the joint venture or cooperative.	NA - The facilities PSE is responsible for reporting are not owned by a joint venture or a cooperative.
98.3(c)(11)(v)	If the facility or supplier is entirely owned by a foreign company, provide the legal name and physical address of the foreign company's highest-level company based in the United States as the United States parent company, and report 100 percent ownership.	NA - The facilities PSE is responsible for reporting are not owned by a foreign company.
98.3(c)(11)(vi)	If the facility or supplier is partially owned by a foreign company and partially owned by one or more U.S. companies, provide the legal name and physical address of the foreign company's highest-level company based in the United States, along with the legal names and physical addresses of the other U.S. parent companies, and report the percent ownership of each of these companies.	NA - The facilities PSE is responsible for reporting are not owned by a foreign company.
98.3(c)(11)(vii)	If the facility or supplier is a federally owned facility, report "U.S. Government" and do not report physical address or percent ownership.	NA - The facilities PSE is responsible for reporting are not federally owned.
98.3(c)(11)(viii)	The facility or supplier must refer to the reporting instructions of the electronic GHG reporting tool regarding standardized conventions for the naming of a parent company.	No response required.
98.3(c)(12)	For the 2010 reporting year only, facilities that have "part 75 units" (i.e. units that are subject to subpart D of this part or units that use the methods in part 75 of this chapter to quantify CO_2 mass emissions in accordance with §98.33(a)(5)) must report annual GHG emissions either in full accordance with paragraphs (c)(4)(i) through (c)(4)(iii) of this section or in full accordance with paragraphs (c)(12)(i) through (c)(12)(iii) of this section. If the latter reporting option is chosen, you must report:	Annual GHG emissions are reported in accordance with paragraphs (c)(4)(i) through (c)(4)(iii) of this section.
98.3(c)(12)(i)	Annual emissions aggregated for all GHG from all applicable source categories, expressed in metric tons of CO_2e calculated using Equation A-1 of this subpart. You must include biogenic CO_2 emissions from part 75 units in these annual emissions, but exclude biogenic CO_2 emissions from any non-part 75 units and other source categories.	NA - Annual GHG emissions are reported in accordance with paragraphs (c)(4)(i) through (c)(4)(iii) of this section.
98.3(c)(12)(ii)	Annual emissions of biogenic CO_2,expressed in metric tons (excluding biogenic CO2 emissions from part 75 units), aggregated for all applicable source categories.	NA - Annual GHG emissions are reported in accordance with paragraphs (c)(4)(i) through (c)(4)(iii) of this section.
98.3(c)(12)(iii)	Annual emissions from each applicable source category, expressed in metric tons of each applicable GHG listed in paragraphs (c)(12)(iii)(A) through (c)(12)(iii)(E) of this section. (A) Biogenic CO_2(excluding biogenic CO_2 emissions from part 75 units). (B) CO_2. You must include biogenic CO_2 emissions from part 75 units in these totals and exclude biogenic CO_2 emissions from other non-part 75 units and other source categories. (C) CH_4. (D) N_2O. (E) Each fluorinated GHG (including those not listed in Table A-1 of this subpart).	NA - Annual GHG emissions are reported in accordance with paragraphs (c)(4)(i) through (c)(4)(iii) of this section.
98.3(c)(13)	An indication of whether the facility includes one or more plant sites that have been assigned a "plant code" (as defined under §98.6) by either the Department of Energy's Energy Information Administration or by the EPA's Clean Air Markets Division.	See Table B-7.

Table B-2. EPA GHG MRR Subpart C - General Stationary Fuel Combustion Sources

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
98.32	You must report CO_2, CH_4, and N_2O mass emissions from each stationary fuel combustion unit, except as otherwise indicated in this subpart.	See response in 98.36(b).
98.36(a)	In addition to the facility-level information required under §98.3, the annual GHG emissions report shall contain the unit-level or process-level data specified in paragraphs (b) through (f) of this section, as applicable, for each stationary fuel combustion source (e.g., individual unit, aggregation of units, common pipe, or common stack) except as otherwise provided in this paragraph (a). For the data specified in paragraphs (b)(9)(iii), (c)(2)(ix), (e)(2)(i), (e)(2)(ii)(A), (e)(2)(ii)(C), (e)(2)(ii)(D), (e)(2)(iv)(A), (e)(2)(iv)(C), (e)(2)(iv)(F), and (e)(2)(ix)(D) through (F) of this section, the owner or operator of a stationary fuel combustion source that does not meet the criteria specified in paragraph (f) of this section may elect either to report the data specified in this sentence in the annual report or to use verification software according to §98.5(b) in lieu of reporting these data. If you elect to use this verification software, you must use the verification software according to §98.5(b) for all of these data that apply to the stationary fuel combustion source.	See response in 98.36(b).
98.36(b)	Units that use the four tiers. You shall report the following information for stationary combustion units that use the Tier 1, Tier 2, Tier 3, or Tier 4 methodology in §98.33(a) to calculate CO_2 emissions, except as otherwise provided in paragraphs (c) and (d) of this section:	See response in the following subsections.
98.36(b)(1)	The unit ID number.	See Table B-7.
98.36(b)(2)	A code representing the type of unit.	See Table B-7.
98.36(b)(3)	Maximum rated heat input capacity of the unit, in MMBtu/hr.	See Table B-7.
98.36(b)(4)	Each type of fuel combusted in the unit during the report year.	See Table B-7.
98.36(b)(5)	The methodology (i.e., tier) used to calculate the CO_2 emissions for each type of fuel combusted (i.e., Tier 1, 2, 3, or 4).	See Table B-7.
98.36(b)(6)	The methodology start date, for each fuel type.	See Table B-7.
98.36(b)(7)	The methodology end date, for each fuel type.	See Table B-7.
98.36(b)(8)	For a unit that uses Tiers 1, 2, or 3:	See response in the following subsections.
98.36(b)(8)(i)	The annual CO_2 mass emissions (including biogenic CO_2), and the annual CH_4, and N_2O mass emissions for each type of fuel combusted during the reporting year, expressed in metric tons of each gas and in metric tons of CO_2e; and	See Table B-7.
98.36(b)(8)(ii)	Metric tons of biogenic CO_2emissions (if applicable).	NA - There is no biogenic CO_2 emissions associated with the facility.
98.36(b)(9)	For a unit that uses Tier 4:	See response in the following subsections.
98.36(b)(9)(i)	If the total annual CO_2 mass emissions measured by the CEMS consists entirely of non-biogenic CO_2 (i.e., CO_2 from fossil fuel combustion plus, if applicable, CO_2 from sorbent and/or process CO_2), report the total annual CO_2 mass emissions, expressed in metric tons. You are not required to report the combustion CO_2 emissions by fuel type.	See Table B-7.
98.36(b)(9)(ii)	Report the total annual CO_2 mass emissions measured by the CEMS. If this total includes both biogenic and non-biogenic CO_2, separately report the annual non-biogenic CO_2 mass emissions and the annual CO_2 mass emissions from biomass combustion, each expressed in metric tons. You are not required to report the combustion CO_2 emissions by fuel type.	NA - There was no unit that burned both fossil fuels and biomass.
98.36(b)(9)(iii)	An estimate of the heat input from each type of fuel listed in Table C-2 of this subpart that was combusted in the unit during the report year.	See Table B-7.
98.36(b)(9)(iv)	The annual CH_4 and N_2O emissions for each type of fuel listed in Table C-2 of this subpart that was combusted in the unit during the report year, expressed in metric tons of each gas and in metric tons of CO_2e.	See Table B-7.
98.36(b)(10)	Annual CO_2 emissions from sorbent (if calculated using Equation C-11 of this subpart), expressed in metric tons.	NA - There was no sorbent used.
98.36(b)(11)	If applicable, the plant code (as defined in §98.6).	See Table B-7.
98.36(c)	Reporting alternatives for units using the four Tiers . You may use any of the applicable reporting alternatives of this paragraph to simplify the unit-level reporting required under paragraph (b) of this section.	NA - Reporting alternatives were not used.
98.36(d)	Units subject to part 75 of this chapter.	See response in the following subsections.
98.36(d)(1)	For stationary combustion units that are subject to subpart D of this part, you shall report the following unit-level information:	See response in the following subsections.
98.36(d)(1)(i)	Unit or stack identification numbers. Use exact same unit, common stack, common pipe, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, CP001, etc.) that are reported under §75.64 of this chapter.	See Table B-7.
98.36(d)(1)(ii)	Annual CO_2 emissions at each monitored location, expressed in both short tons and metric tons. Separate reporting of biogenic CO_2 emissions under §98.3(c)(4)(ii) and §98.3(c)(4)(iii)(A) is optional only for the 2010 reporting year, as provided in §98.3(c)(12).	See Table B-7.
98.36(d)(1)(iii)	Annual CH_4 and N_2O emissions at each monitored location, for each fuel type listed in Table C-2 that was combusted during the year (except as otherwise provided in §98.33(c)(4)(ii)(B)), expressed in metric tons of CO_2e.	See Table B-7.
98.36(d)(1)(iv)	The total heat input from each fuel listed in Table C-2 that was combusted during the year (except as otherwise provided in §98.33(c)(4)(ii)(B)), expressed in MMBtu.	See Table B-7.
98.36(d)(1)(v)	Identification of the Part 75 methodology used to determine the CO_2 mass emissions.	See Table B-7.
98.36(d)(1)(vi)	Methodology start date.	See Table B-7.
98.36(d)(1)(vii)	Methodology end date.	See Table B-7.
98.36(d)(1)(viii)	Acid Rain Program indicator.	See Table B-7.
98.36(d)(1)(ix)	Annual CO_2 mass emissions from the combustion of biomass, expressed in metric tons of CO_2e, except where the reporting provisions of §§98.3(c)(12)(i) through (c)(12)(iii) are implemented for the 2010 reporting year.	See Table B-7.
98.36(d)(1)(x)	If applicable, the plant code (as defined in §98.6).	See Table B-7.
98.36(d)(2)	For units that use the alternative CO_2 mass emissions calculation methods provided in §98.33(a)(5), you shall report the following unit-level information.	NA - Alternative methods were not used.
98.36(e)	*Verification data.* You must keep on file, in a format suitable for inspection and auditing, sufficient data to verify the reported GHG emissions. This data and information must, where indicated in the paragraph (e), be included in the annual GHG emissions report.	See response in the following subsections.
98.36(e)(1)	The applicable verification data specified in this paragraph (e) are not required to be kept on file or reported for units that meet any one of the three following conditions: (i) Are subject to the Acid Rain Program. (ii) Use the alternative methods for units with continuous monitoring systems provided in §98.33(a)(5). (iii) Are not in the Acid Rain Program, but are required to monitor and report CO_2 mass emissions and heat input data year-round, in accordance with part 75 of this chapter.	PSE reports GHG emissions for facilities that do not meet the three conditions. These facilities are listed as not belonging to the Acid Rain Program on Table B-7.

Table B-2. EPA GHG MRR Subpart C - General Stationary Fuel Combustion Sources

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
98.36(e)(2)	For stationary combustion sources using the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies in §98.33(a) to quantify CO_2 emissions, the following additional information shall be kept on file and included in the GHG emissions report, where indicated:	See response in the following subsections.
98.36(e)(2)(i)	For the Tier 1 Calculation Methodology, report the total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during the reporting year, in short tons for solid fuels, gallons for liquid fuels and standard cubic feet for gaseous fuels, or, if applicable, therms or MMBtu for natural gas.	NA - This calculation methodology was not used.
98.36(e)(2)(ii)	For the Tier 2 Calculation Methodology, report: (A) The total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during each month of the reporting year. Express the quantity of each fuel combusted during the measurement period in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels. (B) The frequency of the HHV determinations (e.g., once a month, once per fuel lot). (C) The high heat values used in the CO_2 emissions calculations for each type of fuel combusted during the reporting year, in MMBtu per short ton for solid fuels, MMBtu per gallon for liquid fuels, and MMBtu per scf for gaseous fuels. Report a HHV value for each calendar month in which HHV determination is required. If multiple values are obtained in a given month, report the arithmetic average value for the month. (D) If Equation C-2c of this subpart is used to calculate CO_2 mass emissions, report the total quantity (i.e., pounds) of steam produced from MSW or solid fuel combustion during each month of the reporting year, and the ratio of the maximum rate heat input capacity to the design rated steam output capacity of the unit, in MMBtu per lb of steam. (E) For each HHV used in the CO_2 emissions calculations for each type of fuel combusted during the reporting year, indicate whether the HHV is a measured value or a substitute data value.	See Table B-2 and Table B-7.
98.36(e)(2)(iii)	For the Tier 2 Calculation Methodology, keep records of the methods used to determine the HHV for each type of fuel combusted and the date on which each fuel sample was taken, except where fuel sampling data are received from the fuel supplier. In that case, keep records of the dates on which the results of the fuel analyses for HHV are received.	Records are maintained at each affected facility.
98.36(e)(2)(iv)	For the Tier 3 Calculation Methodology, report: (A) The quantity of each type of fuel combusted in the unit or group of units (as applicable) during each month of the reporting year, in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels. (B) The frequency of carbon content and, if applicable, molecular weight determinations for each type of fuel for the reporting year (e.g., daily, weekly, monthly, semiannually, once per fuel lot). (C) The carbon content and, if applicable, gas molecular weight values used in the emission calculations (including both valid and substitute data values). For each calendar month of the reporting year in which carbon content and, if applicable, molecular weight determination is required, report a value of each parameter. If multiple values of a parameter are obtained in a given month, report the arithmetic average value for the month. Express carbon content as a decimal fraction for solid fuels, kg C per gallon for liquid fuels, and kg C per kg of fuel for gaseous fuels. Express the gas molecular weights in units of kg per kg-mole. (D) The total number of valid carbon content determinations and, if applicable, molecular weight determinations made during the reporting year, for each fuel type. (E) The number of substitute data values used for carbon content and, if applicable, molecular weight used in the annual GHG emissions calculations. (F) The annual average HHV, when measured HHV data, rather than a default HHV from Table C-1 of this subpart, are used to calculate CH_4 and N_2O emissions for a Tier 3 unit, in accordance with §98.33(c)(1). (G) The value of the molar volume constant (MVC) used in Equation C-5 (if applicable).	NA - This calculation methodology was not used.
98.36(e)(2)(v)	For the Tier 3 Calculation Methodology, keep records of the following: (A) For liquid and gaseous fuel combustion, the dates and results of the initial calibrations and periodic recalibrations of the required fuel flow meters. (B) For fuel oil combustion, the method from §98.34(b) used to make tank drop measurements (if applicable). (C) The methods used to determine the carbon content and (if applicable) the molecular weight of each type of fuel combusted. (D) The methods used to calibrate the fuel flow meters). (E) The date on which each fuel sample was taken, except where fuel sampling data are received from the fuel supplier. In that case, keep records of the dates on which the results of the fuel analyses for carbon content and (if applicable) molecular weight are received.	NA - This calculation methodology was not used.
98.36(e)(2)(vi)	For the Tier 4 Calculation Methodology, report: (A) The total number of source operating hours in the reporting year. (B) The cumulative CO_2 mass emissions in each quarter of the reporting year, i.e., the sum of the hourly values calculated from Equation C-6 or C-7 of this subpart (as applicable), in metric tons. (C) For CO_2 concentration, stack gas flow rate, and (if applicable) stack gas moisture content, the percentage of source operating hours in which a substitute data value of each parameter was used in the emissions calculations.	To be addressed by PSE.
98.36(e)(2)(vii)	For the Tier 4 Calculation Methodology, keep records of: (A) Whether the CEMS certification and quality assurance procedures of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program were used. (B) The dates and results of the initial certification tests of the CEMS. (C) The dates and results of the major quality assurance tests performed on the CEMS during the reporting year, i.e., linearity checks, cylinder gas audits, and relative accuracy test audits (RATAs).	These records are maintained in pursuant to each facility's Part 75 Monitoring Plan.
98.36(e)(2)(viii)	If CO_2 emissions that are generated from acid gas scrubbing with sorbent injection are not captured using CEMS, report: (A) The total amount of sorbent used during the report year, in short tons. (B) The molecular weight of the sorbent. (C) The ratio ("R") in Equation C-11 of this subpart.	NA - Not an applicable requirement for facilities under PSE's operational control.

Table B-2. EPA GHG MRR Subpart C - General Stationary Fuel Combustion Sources

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
98.36(e)(2)(ix)	For units that combust both fossil fuel and biomass, when biogenic CO_2 is determined according to §98.33(e)(2), you shall report the following additional information, as applicable: (A) The annual volume of CO_2 emitted from the combustion of all fuels, i.e., Vtotal, in scf. (B) The annual volume of CO_2 emitted from the combustion of fossil fuels, i.e., Vff, in scf. If more than one type of fossil fuel was combusted, report the combustion volume of CO_2 for each fuel separately as well as the total. (C) The annual volume of CO_2 emitted from the combustion of biomass, i.e., Vbio, in scf. (D) The carbon-based F-factor used in Equation C-13 of this subpart, for each type of fossil fuel combusted, in scf CO_2 per MMBtu. (E) The annual average HHV value used in Equation C-13 of this subpart, for each type of fossil fuel combusted, Btu/lb, Btu/gal, or Btu/scf, as appropriate. (F) The total quantity of each type of fossil fuel combusted during the reporting year, in lb, gallons, or scf, as appropriate. (G) Annual biogenic CO_2 mass emissions, in metric tons.	NA - There was no source of biogenic CO2 emissions.
98.36(e)(2)(x)	When ASTM methods D7459-08 (incorporated by reference, see §98.7) and D6866-08 (incorporated by reference, see §98.7) are used to determine the biogenic portion of the annual CO_2 emissions from MSW combustion, as described in §98.34(d), report: (A) The results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO_2 emissions from MSW combustion is 30 percent, report 0.30). (B) The annual biogenic CO_2 mass emissions from MSW combustion, in metric tons.	NA - There was no source of biogenic CO2 emissions.
98.36(e)(2)(xi)	When ASTM methods D7459-08 (incorporated by reference, see §98.7) and D6866-08 (incorporated by reference, see §98.7) are used in accordance with §98.34(e) to determine the biogenic portion of the annual CO_2 emissions from a unit that co-fires biogenic fuels (or partly-biogenic fuels, including tires if you are electing to report biogenic CO_2 emissions from tire combustion) and non-biogenic fuels, you shall report the results of each quarterly sample analysis, expressed as a decimal fraction (*e.g.,* if the biogenic fraction of the CO_2 emissions is 30 percent, report 0.30).	NA - There was no source of biogenic CO2 emissions.
98.36(e)(3)	Within 30 days of receipt of a written request from the Administrator, you shall submit explanations of the following: (i) An explanation of how company records are used to quantify fuel consumption, if the Tier 1 or Tier 2 Calculation Methodology is used to calculate CO_2 emissions. (ii) An explanation of how company records are used to quantify fuel consumption, if solid fuel is combusted and the Tier 3 Calculation Methodology is used to calculate CO_2 emissions. (iii) An explanation of how sorbent usage is quantified. (iv) An explanation of how company records are used to quantify fossil fuel consumption in units that uses CEMS to quantify CO_2 emissions and combusts both fossil fuel and biomass. (v) An explanation of how company records are used to measure steam production, when it is used to calculate CO_2 mass emissions under §98.33(a)(2)(iii) or to quantify solid fuel usage under §98.33(c)(3).	To be addressed by PSE.
98.36(e)(4)	Within 30 days of receipt of a written request from the Administrator, you shall submit the verification data and information described in paragraphs (e)(2)(iii), (e)(2)(v), and (e)(2)(vii) of this section.	To be addressed by PSE.
98.36(f)	Each stationary fuel combustion source (e.g., individual unit, aggregation of units, common pipe, or common stack) subject to reporting under paragraph (b) or (c) of this section must indicate if both of the following two conditions are met:	See response in the following subsections.
98.36(f)(1)	The stationary fuel combustion source contains at least one combustion unit connected to a fuel-fired electric generator owned or operated by an entity that is subject to regulation of customer billing rates by the public utility commission (excluding generators that are connected to combustion units that are subject to subpart D of this part).	This condition is met.
98.36(f)(2)	The stationary fuel combustion source is located at a facility for which the sum of the nameplate capacities for all electric generators specified in paragraph (f)(1) of this section is greater than or equal to 1 megawatt electric output.	This condition is met.

Table B-3. EPA GHG MRR Subpart D - Electricity Generation

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
98.42(a)	For each electricity generating unit that is subject to the requirements of the Acid Rain Program or is otherwise required to monitor and report to EPA CO_2 mass emissions year-round according to 40 CFR part 75, you must report under this subpart the annual mass emissions of CO_2, N_2O, and CH_4 by following the requirements of this subpart.	See Table B-2.
98.42(b)	For each electricity generating unit that is not subject to the Acid Rain Program or otherwise required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O by following the requirements of subpart C.	See Table B-2.
98.42(c)	For each stationary fuel combustion unit that does not generate electricity, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O by following the requirements of subpart C of this part.	See Table B-2.
98.46	The annual report shall comply with the data reporting requirements specified in §98.36(d)(1).	See Table B-2.

Table B-4. EPA GHG MRR Subpart W - Petroleum and Natural Gas Systems

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
98.232(a)	You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraph (b) through (i) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraph (b) through (i) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.	See Table B-8.
98.232(b)	For offshore petroleum and natural gas production, report CO_2, CH_4,and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.232(c)	For an onshore petroleum and natural gas production facility, report CO_2, CH4, and N_2O emissions from only the following source types on a single well-pad or associated with a single well-pad:	NA - PSE does not own or operate facilities that belong to this industry segment.
98.232(d)	For onshore natural gas processing, report CO_2, CH_4, and N_2O emissions from the following sources:	NA - PSE does not own or operate facilities that belong to this industry segment.
98.232(e)	For onshore natural gas transmission compression, report CO_2, CH_4, and N_2O emissions from the following sources:	NA - PSE does not own or operate facilities that belong to this industry segment.
98.232(f)	For underground natural gas storage, report CO_2, CH_4, and N_2O emissions from the following sources:	NA - PSE does not own or operate facilities that belong to this industry segment.
98.232(g)	For LNG storage, report CO_2, CH_4, and N_2O emissions from the following sources:	NA - PSE does not own or operate facilities that belong to this industry segment.
98.232(h)	LNG import and export equipment, report CO_2, CH_4, and N_2O emissions from the following sources:	NA - PSE does not own or operate facilities that belong to this industry segment.
98.232(i)	For natural gas distribution, report CO_2, CH_4, and N_2O emissions from the following sources:	See Table B-8.
98.232(j)	For an onshore petroleum and natural gas gathering and boosting facility, report CO_2, CH_4, and N_2O emissions from the following source types:	NA - PSE does not own or operate facilities that belong to this industry segment.
98.232(k)	Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C except for facilities under onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution. Onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section. Onshore petroleum and natural gas gathering and boosting facilities must report stationary and portable combustion emissions as specified in paragraph (j) of this section.	NA - There are no stationary fuel combustion sources applicable under this subpart.
98.232(l)	You must report under subpart PP of this part (Suppliers of Carbon Dioxide), CO_2 emissions captured and transferred off site by following the requirements of subpart PP.	NA - PSE does is not a supplier of carbon dioxide.
98.232(m)	For onshore natural gas transmission pipeline, report pipeline blowdown CO_2 and CH_4 emissions from blowdown vent stacks.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(a)	The annual report must include the information specified in paragraphs (a)(1) through (10) of this section for each applicable industry segment. The annual report must also include annual emissions totals, in metric tons of each GHG, for each applicable industry segment listed in paragraphs (a)(1) through (10), and each applicable emission source listed in paragraphs (b) through (z) of this section.	See response in the following subsections.
98.236(a)(1)	Onshore petroleum and natural gas production.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(a)(2)	Offshore petroleum and natural gas production.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(a)(3)	Onshore natural gas processing.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(a)(4)	Onshore natural gas transmission compression.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(a)(5)	Underground natural gas storage.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(a)(6)	LNG storage.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(a)(7)	LNG import and export.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(a)(8)	Natural gas distribution.	See Table B-8.
98.236(a)(9)	Onshore petroleum and natural gas gathering and boosting.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(a)(10)	Onshore natural gas transmission pipeline.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(b)	Natural gas pneumatic devices.	NA - PSE does not own or operate this type of equipment.
98.236(c)	Natural gas driven pneumatic pumps.	NA - PSE does not own or operate this type of equipment.
98.236(d)	Acid gas removal units.	NA - PSE does not own or operate this type of equipment.
98.236(e)	Dehydrators.	NA - PSE does not own or operate this type of equipment.
98.236(f)	Liquids unloading.	NA - PSE does not own or operate this type of equipment.
98.236(g)	Completions and workovers with hydraulic fracturing.	NA - PSE does not own or operate this type of equipment.
98.236(h)	Completions and workovers without hydraulic fracturing.	NA - PSE does not own or operate this type of equipment.
98.236(i)	Blowdown vent stacks.	NA - PSE does not own or operate this type of equipment.
98.236(j)	Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.	NA - PSE does not own or operate this type of equipment.
98.236(k)	Transmission storage tanks.	NA - PSE does not own or operate this type of equipment.
98.236(l)	Well testing.	NA - PSE does not own or operate this type of equipment.
98.236(m)	Associated natural gas.	NA - PSE does not own or operate this type of equipment.
98.236(n)	Flare stacks.	NA - PSE does not own or operate this type of equipment.
98.236(o)	Centrifugal compressors.	NA - PSE does not own or operate this type of equipment.
98.236(p)	Reciprocating compressors.	NA - PSE does not own or operate this type of equipment.

Table B-4. EPA GHG MRR Subpart W - Petroleum and Natural Gas Systems

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
98.236(q)	Equipment leak surveys.	NA - PSE accounts for GHG emissions from equipment leak under section (r).
98.236(r)	Equipment leaks by population count.	See Table B-8.
98.236(s)	Offshore petroleum and natural gas production.	NA - PSE does not own or operate this type of equipment.
98.236(t)	[Reserved]	No response required.
98.236(u)	[Reserved]	No response required.
98.236(v)	[Reserved]	No response required.
98.236(w)	EOR injection pumps.	NA - PSE does not own or operate this type of equipment.
98.236(x)	EOR hydrocarbon liquids	NA - PSE does not own or operate this type of equipment.
98.236(y)	[Reserved]	No response required.
98.236(z)	Combustion equipment at onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, and natural gas distribution facilities.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(aa)	Each facility must report the information specified in paragraphs (aa)(1) through (11) of this section, for each applicable industry segment, by using best available data. If a quantity required to be reported is zero, you must report zero as the value.	See response in the following subsections.
98.236(aa)(1)	For onshore petroleum and natural gas production, report the data specified in paragraphs (aa)(1)(i) and (ii) of this section.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(aa)(2)	For offshore production, report the quantities specified in paragraphs (aa)(2)(i) and (ii) of this section.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(aa)(3)	For natural gas processing, report the information specified in paragraphs (aa)(3)(i) through (vii) of this section.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(aa)(4)	For natural gas transmission compression, report the quantity specified in paragraphs (aa)(4)(i) through (v) of this section.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(aa)(5)	For underground natural gas storage, report the quantities specified in paragraphs (aa)(5)(i) through (iii) of this section.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(aa)(6)	For LNG import equipment, report the quantity of LNG imported in the calendar year, in thousand standard cubic feet.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(aa)(7)	For LNG export equipment, report the quantity of LNG exported in the calendar year, in thousand standard cubic feet.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(aa)(8)	For LNG storage, report the quantities specified in paragraphs (aa)(8)(i) through (iii) of this section.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(aa)(9)	For natural gas distribution, report the quantities specified in paragraphs (aa)(9)(i) through (vii) of this section.	See Table B-8.
98.236(aa)(10)	For onshore petroleum and natural gas gathering and boosting facilities, report the quantities specified in paragraphs (aa)(10)(i) through (iv) of this section.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(aa)(11)	For onshore natural gas transmission pipeline facilities, report the quantities specified in paragraphs (aa)(11)(i) through (vi) of this section.	NA - PSE does not own or operate facilities that belong to this industry segment.
98.236(bb)	For any missing data procedures used, report the information in §98.3(c)(8) except as provided in paragraphs (bb)(1) and (2) of this section.	To be addressed by PSE.
98.236(cc)	If you elect to delay reporting the information in paragraph (g)(5)(i), (g)(5)(ii), (g)(5)(iii)(A), (g)(5)(iii)(B), (h)(1)(iv), (h)(2)(iv), (j)(1)(iii), (j)(2)(i)(A), (l)(1)(iv), (l)(2)(iv), (l)(3)(iii), (l)(4)(iii), (m)(5), or (m)(6) of this section, you must report the information required in that paragraph no later than the date 2 years following the date specified in §98.3(b) introductory text.	To be addressed by PSE.

Table B-5. EPA GHG MRR Subpart DD - Electrical Transmission and Distribution Equipment Use

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
98.302	You must report total SF_6 and PFC emissions from your facility (including emissions from fugitive equipment leaks, installation, servicing, equipment decommissioning and disposal, and from storage cylinders) resulting from the transmission and distribution servicing inventory and equipment listed in §98.300(a). For acquisitions of equipment containing or insulated with SF_6 or PFCs, you must report emissions from the equipment after the title to the equipment is transferred to the electric power transmission or distribution entity.	See Table B-9.
98.306	In addition to the information required by §98.3(c), each annual report must contain the following information for each electric power system, by chemical:	See response in the following subsections.
98.306(a)	Nameplate capacity of equipment (pounds) containing SF_6 and nameplate capacity of equipment (pounds) containing each PFC:	See Table B-9.
98.306(a)(1)	Existing at the beginning of the year (excluding hermetically sealed-pressure switchgear).	See Table B-9.
98.306(a)(2)	New during the year (all SF_6-insulated equipment, including hermetically sealed-pressure switchgear).	See Table B-9.
98.306(a)(3)	Retired during the year (all SF_6-insulated equipment, including hermetically sealed-pressure switchgear).	See Table B-9.
98.306(b)	Transmission miles (length of lines carrying voltages above 35 kilovolt).	See Table B-9.
98.306(c)	Distribution miles (length of lines carrying voltages at or below 35 kilovolt).	See Table B-9.
98.306(d)	Pounds of SF_6 and PFC stored in containers, but not in energized equipment, at the beginning of the year.	See Table B-9.
98.306(e)	Pounds of SF_6 and PFC stored in containers, but not in energized equipment, at the end of the year.	See Table B-9.
98.306(f)	Pounds of SF_6 and PFC purchased in bulk from chemical producers or distributors.	See Table B-9.
98.306(g)	Pounds of SF_6 and PFC purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear.	See Table B-9.
98.306(h)	Pounds of SF_6 and PFC returned to facility after off-site recycling.	See Table B-9.
98.306(i)	Pounds of SF_6 and PFC in bulk and contained in equipment sold to other entities.	See Table B-9.
98.306(j)	Pounds of SF_6 and PFC returned to suppliers.	See Table B-9.
98.306(k)	Pounds of SF_6 and PFC sent off-site for recycling.	See Table B-9.
98.306(l)	Pounds of SF_6 and PFC sent off-site for destruction.	See Table B-9.

Table B-6. EPA GHG MRR Subpart NN - Suppliers of Natural Gas and Natural Gas Liquids

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
98.402(a)	NGL fractionators must report the CO_2 emissions that would result from the complete combustion or oxidation of the annual quantity of ethane, propane, normal butane, isobutane, and pentanes plus that is produced and sold or delivered to others.	NA - This facility does not have NGL fractionation operations.
98.402(b)	LDCs must report the CO_2 emissions that would result from the complete combustion or oxidation of the annual volumes of natural gas provided to end-users on their distribution systems.	See Table B-10.
98.406(b)(1)	Annual volume in Mscf of natural gas received by the LDC at its city gate stations for redelivery on the LDC's distribution system, including for use by the LDC.	See Table B-10.
98.406(b)(2)	Annual volume in Mscf of natural gas placed into storage or liquefied and stored (Fuel1 in Equation NN-5a).	See Table B-10.
98.406(b)(3)	Annual volume in Mscf of natural gas withdrawn from on-system storage and annual volume in Mscf of vaporized liquefied natural gas (LNG) withdrawn from storage for delivery on the distribution system (Fuel2 in Equation NN-5a).	See Table B-10.
98.406(b)(4)	[Reserved]	No response required.
98.406(b)(5)	Annual volume in Mscf of natural gas that bypassed the city gate(s) and was supplied through the LDC distribution system. This includes natural gas from producers and natural gas processing plants from local production, or natural gas that was vaporized upon receipt and delivered, and any other source that bypassed the city gate ($Fuel_z$ in Equation NN-5b).	See Table B-10.
98.406(b)(6)	Annual volume in Mscf of natural gas delivered to downstream gas transmission pipelines and other local distribution companies.	See Table B-10.
98.406(b)(7)	Annual volume in Mscf of natural gas delivered by the LDC to each large end-user as defined in §98.403(b)(2)(i) of this section.	See Table B-10.
98.406(b)(8)	The total annual CO_2 mass emissions (metric tons) associated with the volumes in paragraphs (b)(1) through (b)(7) of this section, calculated in accordance with § 98.403(a) and (b)(1) through (b)(3).	See Table B-10.
98.406(b)(9)	Annual CO_2 emissions (metric tons) that would result from the complete combustion or oxidation of the annual supply of natural gas to end-users registering less than 460,000 Mscf, calculated in accordance with §98.403(b)(4). If the calculated value is negative, the reporter shall report the value as zero.	See Table B-10.
98.406(b)(10)	The specific industry standard used to develop the volume reported in paragraph (b)(1) of this section.	To be addressed by PSE.
98.406(b)(11)	If the LDC developed reporter-specific EFs or HHVs, report the following:	NA - No reporter-specific EFs or HHVs were used.
98.406(b)(12)	The customer name, address, and meter number of each meter reading used to report in paragraph (b)(7) of this section. Additionally, report whether the quantity of natural gas reported in paragraph (b)(7) of this section is the total quantity delivered to a large end-user's facility, or the quantity delivered to a specific meter located at the facility.	See Table B-10.
98.406(b)(12)(i)	If known, report the EIA identification number of each LDC customer.	To be addressed by PSE.
98.406(b)(13)	The annual volume in Mscf of natural gas delivered by the local distribution company to each of the following end-use categories. For definitions of these categories, refer to EIA Form 176 (Annual Report of Natural Gas and Supplemental Gas Supply & Disposition) and Instructions.	See response in the following subsections.
98.406(b)(13)(i)	Residential consumers.	See Table B-10.
98.406(b)(13)(ii)	Commercial consumers.	See Table B-10.
98.406(b)(13)(iii)	Industrial consumers.	See Table B-10.
98.406(b)(13)(iv)	Electricity generating facilities.	See Table B-10.
98.406(c)	Each reporter shall report the number of days in the reporting year for which substitute data procedures were used for the following purpose:	See response in the following subsections.
98.406(c)(i)	To measure quantity.	To be addressed by PSE.
98.406(c)(ii)	To develop HHV(s).	NA - No reporter-specific EFs or HHVs were used.
98.406(c)(iii)	To develop EF(s).	NA - No reporter-specific EFs or HHVs were used.

Table B-7. EPA GHG MRR Subpart C Calculations

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Unit	Plant Code [2]	Unit ID [1]	Unit Type	PSE Share [3]	Maximum Rate Heat Input Capacity (MMBtu) [3]	Fuel Type	HI [4],[5] (MMBtu)	Acid Rain Program [2]	Emissions Include Emissions from a Cogeneration Unit Located at the Facility [2],[6]	Tier [1]	Method Start and End Date	Emissions (metric ton)			Emissions in CO_2e (metric ton)				Emissions (short ton)			Emissions in CO_2e (short ton)			
												CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	Total	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	Total
Colstrip Unit 1	6076	1	Coal	50%	1,047	Coal	19,415,318	Yes	NA	4	1/1/2017 - 12/31/2017	923,567.53	106.86	15.55	923,567.53	2,671.52	4,633.19	930,872.24	1,018,058.93	117.79	17.14	1,018,058.93	2,944.85	5,107.21	1,026,111.00
Colstrip Unit 2		2	Coal	50%		Coal	20,709,549	Yes	NA	4	1/1/2017 - 12/31/2017	984,965.96	113.93	16.57	984,965.96	2,848.25	4,938.79	992,753.00	1,085,739.12	125.59	18.27	1,085,739.12	3,139.66	5,444.09	1,094,322.86
Colstrip Unit 3		3	Coal	25%	1,262	Coal	55,260,212	Yes	NA	4	1/1/2017 - 12/31/2017	1,314,441.05	151.99	22.11	1,314,441.05	3,799.85	6,588.71	1,324,829.61	1,448,923.24	167.54	24.37	1,448,923.24	4,188.62	7,262.81	1,460,374.66
Colstrip Unit 4		4	Coal	25%		Coal	53,528,688	Yes	NA	4	1/1/2017 - 12/31/2017	1,273,253.98	147.23	21.42	1,273,253.98	3,680.82	6,382.34	1,283,317.13	1,403,522.26	162.30	23.61	1,403,522.26	4,057.41	7,035.32	1,414,614.99
Encogen 1	7870	CT1	Natural gas cogeneration	100%	563	Natural Gas	1,185,545	Yes	Yes	4	1/1/2017 - 12/31/2017	63,915.80	1.19	0.12	63,915.80	29.64	35.33	63,980.77	70,455.11	1.31	0.13	70,455.11	32.67	38.94	70,526.72
Encogen 2		CT2	Natural gas cogeneration			Natural Gas	1,151,373	Yes	Yes	4	1/1/2017 - 12/31/2017	62,070.37	1.15	0.12	62,070.37	28.78	34.31	62,133.47	68,420.88	1.27	0.13	68,420.88	31.73	37.82	68,490.43
Encogen 3		CT3	Natural gas cogeneration			Natural Gas	1,215,390	Yes	Yes	4	1/1/2017 - 12/31/2017	65,527.10	1.22	0.12	65,527.10	30.38	36.22	65,593.71	72,231.27	1.34	0.13	72,231.27	33.49	39.92	72,304.68
Ferndale 1	54537	CT-1A	Natural gas combined cycle	100%	863	Natural Gas	4,415,730	Yes	NA	4	1/1/2017 - 12/31/2017	238,067.35	4.42	0.44	238,067.35	110.39	131.59	238,309.33	262,424.34	4.87	0.49	262,424.34	121.69	145.05	262,691.07
Ferndale 2		CT-1B	Natural gas combined cycle			Natural Gas	4,446,354	Yes	NA	4	1/1/2017 - 12/31/2017	239,721.58	4.45	0.44	239,721.58	111.16	132.50	239,965.24	264,247.81	4.90	0.49	264,247.81	122.53	146.06	264,516.39
Frederickson Unit 1	55818	F1CT	Natural gas combined cycle	49.85%	464	Natural Gas	4,752,450	Yes	Yes	4	1/1/2017 - 12/31/2017	256,217.91	2.37	0.24	256,217.91	59.23	70.60	256,347.73	282,431.89	2.61	0.26	282,431.89	65.29	77.82	282,575.00
Fredonia 1	607	CT1	Dual-fuel combustion turbines	100%	706	Natural Gas	781,737	No	NA	2	1/1/2017 - 12/31/2017	41,478.95	0.78	0.08	41,478.95	19.54	23.30	41,521.79	45,722.72	0.86	0.09	45,722.72	21.54	25.68	45,769.94
						Distillate Fuel Oil No. 2	3,334	No	NA	2	1/1/2017 - 12/31/2017	246.62	0.01	0.00	246.62	0.25	0.60	247.47	271.85	0.01	0.00	271.85	0.28	0.66	272.78
Fredonia 2		CT2	Dual-fuel combustion turbines			Natural Gas	1,780,500	No	NA	2	1/1/2017 - 12/31/2017	94,473.32	1.78	0.18	94,473.32	44.51	53.06	94,570.89	104,139.01	1.96	0.20	104,139.01	49.07	58.49	104,246.56
						Distillate Fuel Oil No. 2	569	No	NA	2	1/1/2017 - 12/31/2017	42.06	0.00	0.00	42.06	0.04	0.10	42.21	46.37	0.00	0.00	46.37	0.05	0.11	46.52
Fredonia 3		CT3	Dual-fuel combustion turbines	100%	365	Natural Gas	36,261	Yes	NA	4	1/1/2017 - 12/31/2017	1,705.87	0.04	0.00	1,705.87	0.91	1.08	1,707.86	1,880.40	0.04	0.00	1,880.40	1.00	1.19	1,882.59
Fredonia 4		CT4	Dual-fuel combustion turbines			Natural Gas	303,996	Yes	NA	4	1/1/2017 - 12/31/2017	16,436.88	0.30	0.03	16,436.88	7.60	9.06	16,453.53	18,118.55	0.34	0.03	18,118.55	8.38	9.99	18,136.92
Frederickson 1	99	CT1	Dual-fuel combustion turbines	100%	508	Natural Gas	750,585	No	Yes	2	1/1/2017 - 12/31/2017	39,826.05	0.75	0.08	39,826.05	18.76	22.37	39,867.18	43,900.70	0.83	0.08	43,900.70	20.68	24.66	43,946.04
						Distillate Fuel Oil No. 2	2,534	No	Yes	2	1/1/2017 - 12/31/2017	187.44	0.01	0.00	187.44	0.19	0.45	188.08	206.61	0.01	0.00	206.61	0.21	0.50	207.32
Frederickson 2		CT2	Dual-fuel combustion turbines			Natural Gas	564,359	No	Yes	2	1/1/2017 - 12/31/2017	29,944.91	0.56	0.06	29,944.91	14.11	16.82	29,975.83	33,008.61	0.62	0.06	33,008.61	15.55	18.54	33,042.70
						Distillate Fuel Oil No. 2	0	No	Yes	2	1/1/2017 - 12/31/2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Goldendale	55482	CT-1	Natural gas combined cycle	100%	1,075	Natural Gas	13,510,385	Yes	Yes	4	1/1/2017 - 12/31/2017	728,382.59	13.51	1.35	728,382.59	337.76	402.61	729,122.96	802,904.37	14.89	1.49	802,904.37	372.32	443.80	803,720.49
Mint Farm	55700	CTG1	Natural gas combined cycle	100%	1,013	Natural Gas	14,072,251	Yes	Yes	4	1/1/2017 - 12/31/2017	758,675.98	14.07	1.41	758,675.98	351.81	419.35	759,447.14	836,297.11	15.51	1.55	836,297.11	387.80	462.26	837,147.17
Sumas	54476	CT-1	Natural gas cogeneration	100%	433	Natural Gas	4,219,415	Yes	Yes	4	1/1/2017 - 12/31/2017	227,480.66	4.22	0.42	227,480.66	105.49	125.74	227,711.88	250,754.50	4.65	0.47	250,754.50	116.28	138.60	251,009.38
Whitehorn 2	6120	CT2	Dual-fuel combustion turbines	100%	508	Natural Gas	68,428	No	NA	2	1/1/2017 - 12/31/2017	3,630.80	0.07	0.01	3,630.80	1.71	2.04	3,634.55	4,002.28	0.08	0.01	4,002.28	1.89	2.25	4,006.41
						Distillate Fuel Oil No. 2	544	No	NA	2	1/1/2017 - 12/31/2017	40.24	0.00	0.00	40.24	0.04	0.10	40.38	44.36	0.00	0.00	44.36	0.04	0.11	44.51
Whitehorn 3		CT3	Dual-fuel combustion turbines			Natural Gas	49,613	No	NA	2	1/1/2017 - 12/31/2017	2,632.48	0.05	0.00	2,632.48	1.24	1.48	2,635.20	2,901.81	0.05	0.01	2,901.81	1.37	1.63	2,904.81
						Distillate Fuel Oil No. 2	7,120	No	NA	2	1/1/2017 - 12/31/2017	526.60	0.02	0.00	526.60	0.53	1.27	528.41	580.48	0.02	0.00	580.48	0.59	1.40	582.47
Total												**7,367,460.07**	**570.98**	**80.75**	**7,367,460.07**	**14,274.52**	**24,062.99**	**7,405,797.59**	**8,121,234.57**	**629.40**	**89.01**	**8,121,234.57**	**15,734.97**	**26,524.91**	**8,163,494.45**

Calculation Inputs:

Parameter	Value	(UOM)
Unit Conversion	1.102	short ton/ metric ton

Data Source:
[1] ECMPS Feedback (EPA)
[2] PSE ECMPS Reports
[3] Puget Energy Form 10-K

Note(s):
(1) See Table A-1 and A-2 for calculation details
(2) See Table A-4 for Global Warming Potentials
(3) Maximum Rate Heat Input Capacity calculated using 1 MW = 3.412 MMBtu/hr
(4) HI = Cumulative annual heat input
(5) NR = Not required for calculations
(6) NA = Not applicable, no cogeneration unit

Table B-8. EPA GHG MRR Subpart W Calculations

Puget Sound Energy - 2019 Greenhouse Gas Inventory

Component	Emission Factor [7]	(UOM)	Count [1],[2],(1)	Duration Component Leaking (hr) (2)	Emissions (metric ton) CO_2	Emissions (metric ton) CH_4	Emissions in CO_2e (metric ton) (3) CO_2e
T&D Gate							
Open-ended Line	26.131	scf/hr/component	9	8,760	1.19 {2}	39.56 {2}	990.1
Below Grade M&R Station							
Below Grade M&R Station Components > 300 psig	1.30	scf/hr/station	3	8,760	0.02 {2}	0.66 {2}	16.4
Below Grade M&R Station Components 100 to 300 psig	0.20	scf/hr/station	354	8,760	0.36 {2}	11.91 {2}	298.1
Below Grade M&R Station Components < 100 psig	0.10	scf/hr/station	12	8,760	0.01 {2}	0.20 {2}	5.1
Below Grade T&D Station Components > 300 psig	1.30	scf/hr/station	0	8,760	0.00 {2}	0.00 {2}	0.0
Below Grade T&D Station Components 100 to 300 psig	0.20	scf/hr/station	2	8,760	0.00 {2}	0.07 {2}	1.7
Below Grade T&D Station Components < 100 psig	0.10	scf/hr/station	0	8,760	0.00 {2}	0.00 {2}	0.0
Below Grade M&R Station Total					**0.39**	**12.83**	**321.2**
Distribution Mains							
Unprotected Steel	12.58	scf/hr/mile	0	8,760	0.00 {2}	0.00 {2}	0.0
Protected Steel	0.35	scf/hr/mile	4,069	8,760	7.22 {2}	239.54 {2}	5,995.6
Plastic	1.13	scf/hr/mile	8,825	8,760	50.55 {2}	1,677.29 {2}	41,982.8
Cast Iron	27.25	scf/hr/mile	0	8,760	0.00 {2}	0.00 {2}	0.0
Distribution Mains Total					**57.8**	**1916.8**	**47,978.4**
Distribution Services							
Unprotected Steel	0.19	scf/hr/#services	0	8,760	0.00 {2}	0.00 {2}	0.0
Protected Steel	0.02	scf/hr/#services	120,549	8,760	12.22 {2}	405.51 {2}	10,149.9
Plastic	0.001	scf/hr/#services	702,397	8,760	3.56 {2}	118.14 {2}	2,957.0
Copper	0.03	scf/hr/#services	0	8,760	0.00 {2}	0.00 {2}	0.0
Distribution Services Total					**15.8**	**523.6**	**13,106.9**
Total Leak Emissions					**73.93**	**2,453.30**	**62,396.61**

Count of external fuel combustion units with a rated heat capacity less than 5 MMBtu/hr: 13

Combustion Emissions Using NG (Gig Harbor Vaporizer, Pipeline Heaters >5 MMBtu)	54.40	kg CO2 / MMBtu	17,511	MMBtu	952.61	metric ton CO2	952.61
	0.001	kg CH4 / MMBtu	17,511	MMBtu	0.0175	metric ton CH4	0.438
	0.0001	kg N2O / MMBtu	17,511	MMBtu	0.00175	metric ton N2O	0.522
						Total Combustion	**953.57**

For stationary and portable combustion units (Tab "(z) Combustion Equipment") burning fuels listed in Table Z.3 (LDC Subpart W Calculation Tool, RY17 v2)

Total Emissions (Leak & Combustion) **63,350.18**

Other Reporting Data:

98.236(r)(2)(i)	Number of above grade T-D transfer stations at the facility	39		[1]
98.236(r)(2)(ii)	Number of above grade metering-regulating stations that are not T-D transfer stations at the facility	121		[1]
[98.236(r)(2)(iii)	Total number of meter/regulator runs at above grade M&R stations that are not above grade T-D transfer stations	121		[1]
93.236(aa)(9)(i)	The quantity of natural gas received at all custody transfer stations in the calendar year, in thousand standard cubic feet. This value may include meter corrections, but only for the calendar year covered by the annual report.	117,866,839	Mscf	[8]
93.236(aa)(9)(ii)	The quantity of natural gas withdrawn from in-system storage in the calendar year, in thousand standard cubic feet.	0	Mscf	[8]
93.236(aa)(9)(iii)	The quantity of natural gas added to in-system storage in the calendar year, in thousand standard cubic feet.	0	Mscf	[8]
93.236(aa)(9)(iv)	The quantity of natural gas delivered to end users, in thousand standard cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for.	22,194,007	Mscf	[8]
93.236(aa)(9)(v)	The quantity of natural gas transferred to third parties such as other LDCs or pipelines, in thousand standard cubic feet. This value does not include stolen gas, or gas that is otherwise unaccounted for.	16,057	Mscf	[8]

Calculation Inputs:

GHG	GHG Concentration [4],[5]	Density (kg/ft^3) [6]
CO_2	1.1E-02	0.0526
CH_4	1	0.0192
N_2O	NA	0.0526

Calculation Methodology:
{1} Reserved
{2} EPA GHG MRR Subpart W (40 CFR 98.233(r)) (Eq. W-32A)
{3} Reserved

Data Source:
[1] Subpart W Reporting Form
[2] PSE M&R Survey
[3] Puget Energy Form 10-K
[4] Reserved
[5] EPA GHG MRR Subpart W (40 CFR 98.233(r)) (Eq. W-32A)
[6] EPA GHG MRR Subpart W (40 CFR 98.233(v)) (Eq. W-36)
[7] EPA GHG MRR Subpart W (40 CFR 98.238), Table W-7
[8] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176

Note(s):
(1) Count represents number of leaking components
(2) Duration = 8,760 hr since one leak detection survey was conducted for the entire calendar year
(3) See Table A-4 for Global Warming Potentials

Table B-9. EPA GHG MRR Subpart DD Calculations

Puget Sound Energy - 2019 Greenhouse Gas Inventory

User Emissions	**26**	**lb**
	0.012	**metric ton**
	265	**metric ton CO_2e**

Calculation Methodology:
{2} EPA GHG MRR Subpart DD (40 CFR 98.303(a)) (Eq. DD-1)

Data Source:
[1] Subpart DD Reporting Form

Note(s):
(1) See Table A-4 for Global Warming Potentials

Table B-10. EPA GHG MRR Subpart NN Calculations

Puget Sound Energy - 2019 Greenhouse Gas Inventory

98.403(a)

Natural Gas Received at City Gate

Fuel	117,866,839	Mscf	[1]	EIA-176 Section 4.0
EF	0.0544	metric ton CO_2 / Mscf	[2]	
CO_{2i}	**6,411,956**	**metric ton**	{1}, (1)	

98.403(b)(1)

Natural Gas Received for Redelivery to Downstream Gas Transmission Pipelines and Other LDC

Fuel	22,194,007	Mscf	[3]	Do Not Own, Transport Gas (Sum of Commercial / Industrial EIA-176)
EF	0.0544	metric ton CO_2 / Mscf	[2]	
CO_{2j}	**1,207,354**	**metric ton**	{2}	

98.403(b)(2)

Natural Gas Delivered to Each Meter Registering a Supply ≥ 460,000 Mscf per Year

Consumer Name	Volume (Mscf)	Service Address	Meter #
UNIVERSITY OF WASHINGTON	1,648,223	3900 Jefferson Road	5000813589
Total	**1,648,223**		

Fuel	1,648,223	Mscf	[4]
EF	0.0544	metric ton CO_2 / Mscf	[2]
CO_{2k}	**89,663**	**metric ton**	{3}

98.403(b)(3)

Natural Gas Received at City Gate Injected into On-System Storage, and/or Liquefied and Stored

Natural Gas Added to Storage On-System Storage or Liquefied and Stored (*Gig Harbor only*)

Fuel	0	Mscf	[5]

Natural Gas Removed from Storage or Vaporized and Removed from Storage and Used for Deliveries to Customers or Other LCDs (*Gig Harbor only*)

Fuel	0	Mscf	[6]
EF	0.0544	metric ton CO_2 / Mscf	[2]
CO_{2l}	**0**	**metric ton**	{4}

Natural Gas from Producers and Natural Gas Processing Plants from Local Production, or Natural Gas Received as Liquid, Vaporized and Delivered, and any other source that Bypassed the City Gate

Fuel	16,057	Mscf	[7]
EF	0.0544	metric ton CO_2 / Mscf	[2]

Source	Volume (Mscf)	
	Total	
BEW-Cedar Hills	1,600,302	Cedar Hills RNG is purchased by PSE and does not connect to the PSE gas system (it is connected to Northwest Pipeline) and the environmental attributes are sold by PSE into California anyway- so it does not count for PSE.
King County Metro	265,769	King County Renton Wastewater (Metro) does connect to PSE's system, however, it is not PSE's gas and attributes are sold into California– so it does not count either.
LNG Received at Gig Harbor	23,514	LNG deliveries to Gig Harbor by tanker truck
LNG Vaporized at Gig Harbor	16,057	Vaporized for peak shaving supply that bypasses City Gate
Total	**16,057**	

CO_{2n}	**874**	**metric ton**	{5}

98.403(b)(4)

Total CO_2 Emissions

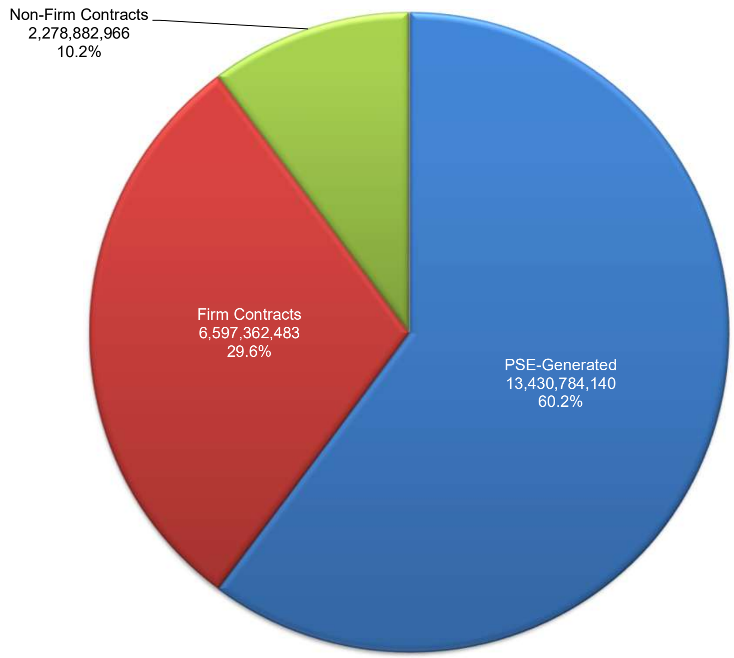
CO_2	**5,115,812**	**metric ton**	{6}

Total Natural Gas Supply

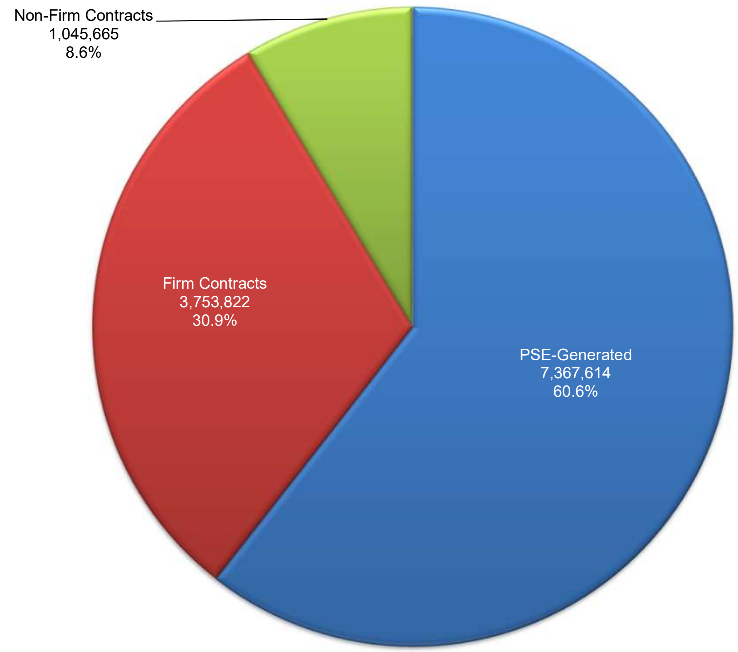
Natural Gas Supply	**94,040,666**	**Mscf**
	940,406,665	**thm**

Figure 1. Total Electricity and its CO2 Emissions

Puget Sound Energy - 2019 Greenhouse Gas Inventory



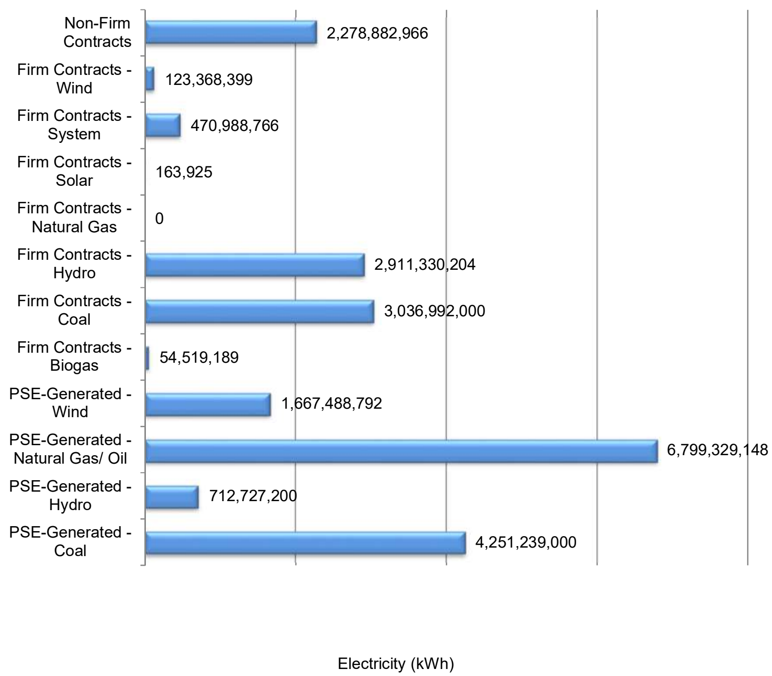
Electricity (kWh)



CO_2 Emissions (metric ton)

Figure 2. Total Electricity by Generation Source and its CO2 Emissions

Puget Sound Energy - 2019 Greenhouse Gas Inventory



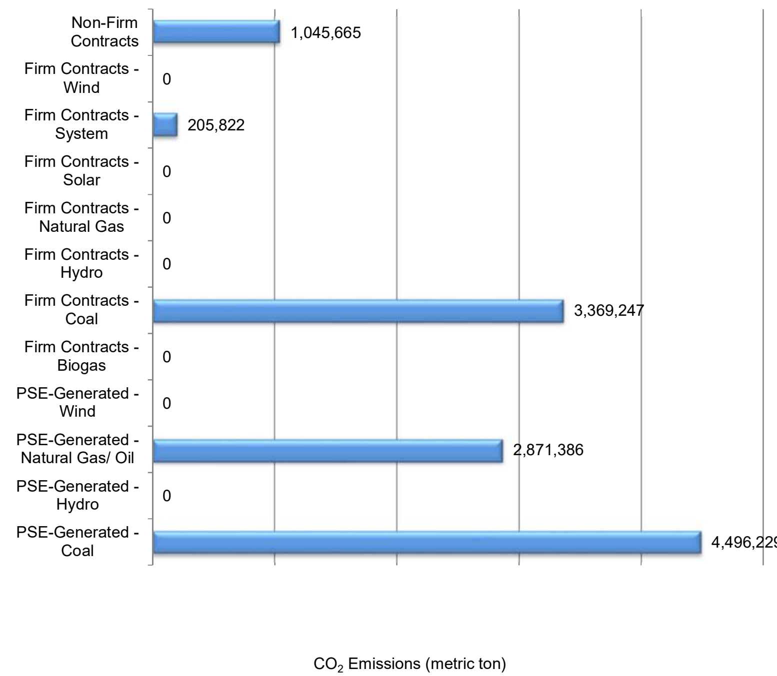
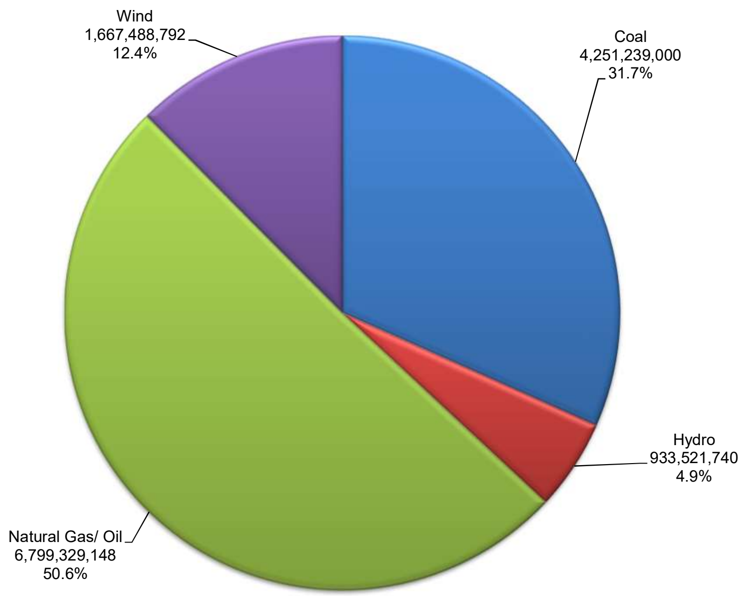
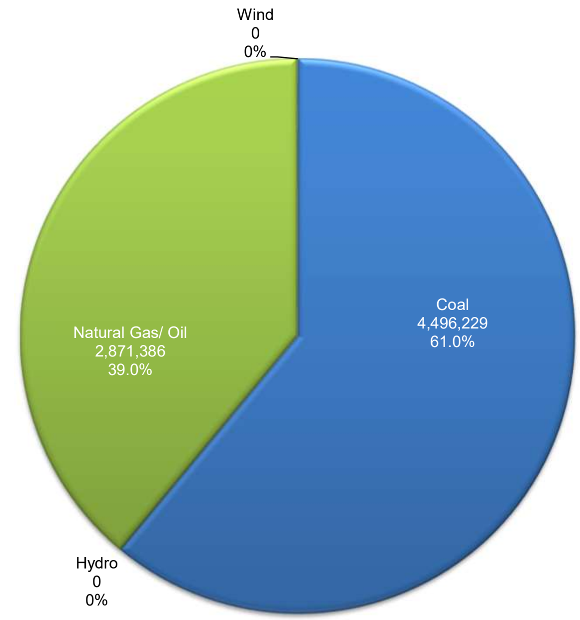


Figure 3. PSE-Generated Electricity by Generation Source and its CO2 Emissions

Puget Sound Energy - 2019 Greenhouse Gas Inventory



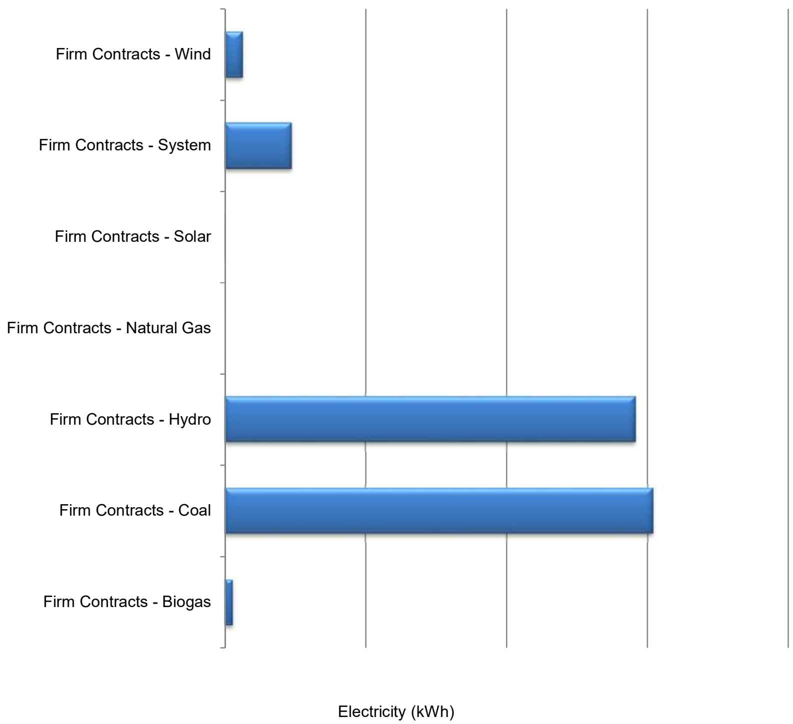
Electricity (kWh)



CO_2 Emissions (metric ton)

Figure 4. Firm Contract Purchased Electricity and its CO2 Emissions

Puget Sound Energy - 2019 Greenhouse Gas Inventory



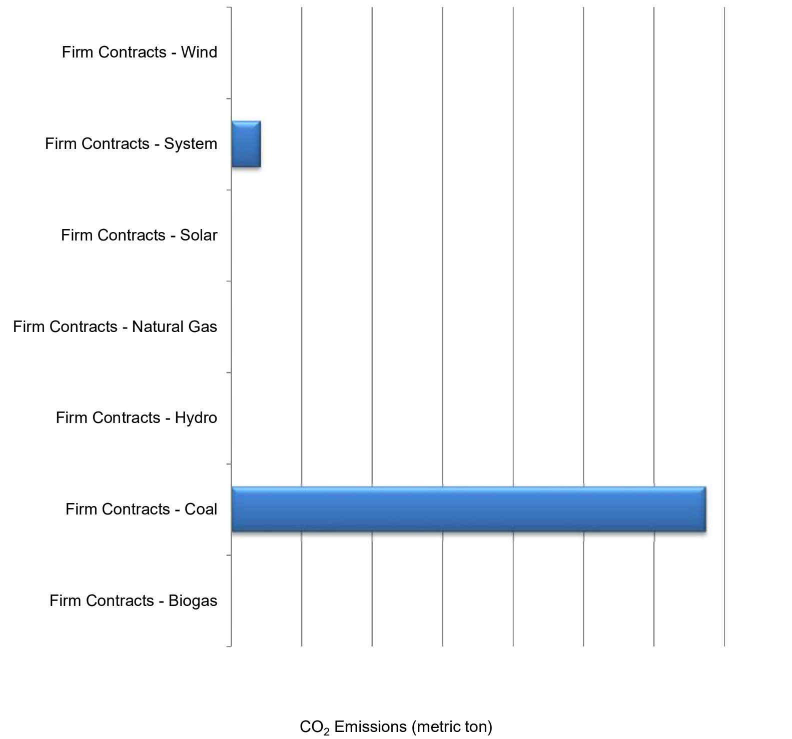
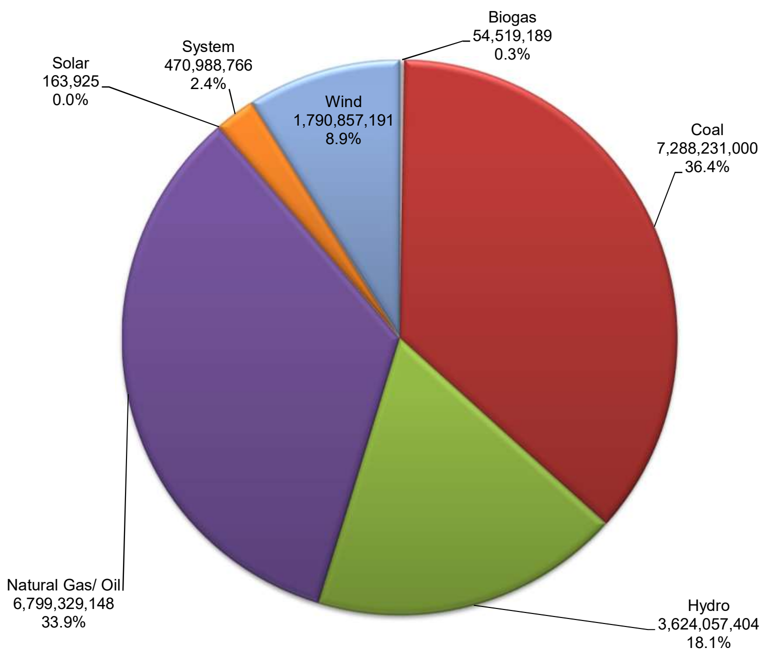
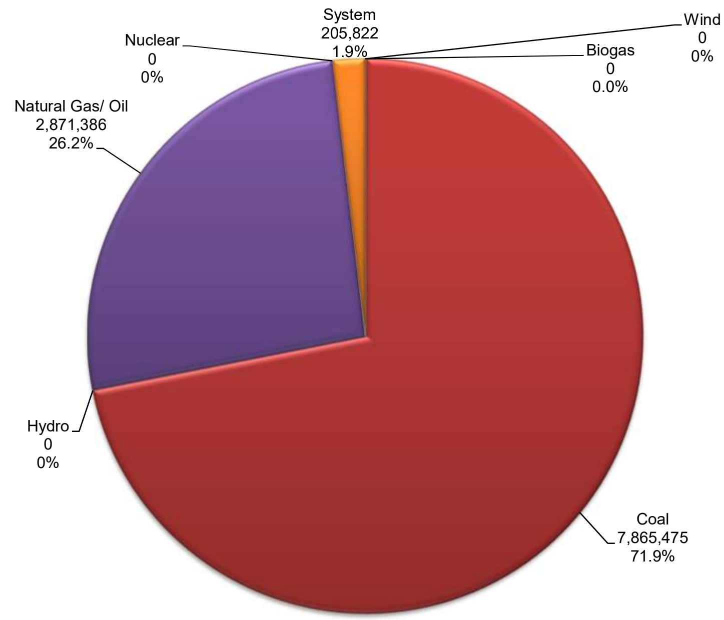


Figure 5. PSE-Generated and Firm Contract Purchased Electricity by Generation Source and its CO2 Emissions

Puget Sound Energy - 2019 Greenhouse Gas Inventory



Electricity (kWh)



CO_2 Emissions (metric ton)