

2015 Greenhouse Gas Inventory

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Puget Sound Energy

2015 Greenhouse Gas Inventory

September 2016

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LIST OF ACRONYMS

Btu	British thermal unit
CCGT	Combined cycle gas turbine
CFR	Code of Federal Regulations
CH ₄	Methane
CO ₂	Carbon dioxide
CO ₂ e	Carbon dioxide equivalent
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EPA	United States Environmental Protection Agency
ft ³	Cubic feet
GHG	Greenhouse gas
GHG MRR	Greenhouse Gas Mandatory Reporting Rule
GWP	Global warming potential
HFCs	Hydrofluorocarbons
IPCC	Intergovernmental Panel on Climate Change
kWh	Kilowatt hour
lb	Pounds
M&R	Metering and regulating
Mscf	Thousand standard cubic feet
MWh	Megawatt hour

N ₂ O	Nitrous oxide
NC	Not calculated
NRDC	Natural Resources Defense Council
NWPP	Northwest Power Pool
PFCs	Perfluorocarbons
PSE	Puget Sound Energy
PURPA	Public Utility Regulatory Policies Act
SCGT	Semi-closed gas turbine
SF ₆	Sulfur hexafluoride
T-D	Transmission and distribution
WAC	Washington Administrative Code
WBCSD	World Business Council for Sustainable Development
WECC	Western Electricity Coordinating Council
WRI	World Resources Institute

EXECUTIVE SUMMARY

Puget Sound Energy's (PSE) operating rates and greenhouse gas (GHG) emissions for calendar year 2015 are summarized below 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.

Table ES-1. Calendar Year 2015 Operating Rates

	Electric Operations	Natural Gas Operations
Throughput	25,735,831,239 kWh	791,212,000 therm
Customers Served (Average)	1,103,635	795,013
Revenue (000)	\$2,128,468	\$947,549

Note(s): kWh = Kilowatt hour.

Table ES-2. Calendar Year 2015 Greenhouse Gas Emissions by Scope

	CO ₂		CH ₄		N ₂ O		SF ₆	
	metric ton	%	metric ton	%	metric ton	%	metric ton	%
PSE-owned Electric Operations	7,512,958	100%	592	20%	85	100%	1.26	100%
PSE-owned Natural Gas Operations	72	0%	2,341	80%	0	0%	0	NC
Total Scope I	7,512,031	100%	2,933	100%	85	100%	1.26	100%
Electricity Purchases	4,427,155	51%	64	100%	107	100%	0	NC
Natural Gas Supply to End-Users	4,282,956	49%	0	0%	0	0%	0	NC
Total Scope III	8,710,111	100%	64	100%	107	100%	0	NC

	CO ₂		CH ₄		N ₂ O		SF ₆	
	metric ton	%	metric ton	%	metric ton	%	metric ton	%
Total Outside Scope	34,537	100%	0	NC	0	NC	0	NC

Note(s): CO₂ = carbon dioxide, CH₄ = methane, N₂O = nitrous oxide, SF₆ = sulfur hexafluoride, NC = not calculated.

Table ES-3. Calendar Year 2015 Greenhouse Gas Emissions by Source

	CO ₂		CH ₄		N ₂ O		SF ₆	
	metric ton	%	metric ton	%	metric ton	%	metric ton	%
Generated and Purchased Electricity	11,974,650	73.7%	656	21.9%	193	100%	1.26	100%
Natural Gas Operations	72	0.0004%	2,341	78.1%	0	0%	0	0%
Natural Gas Supply to End-Users	4,282,956	26.3%	0	0%	0	0%	0	0%
Emissions from All Sources	16,257,679	100%	2,998	100%	193	100%	1.26	100%

Note(s): CO₂ = carbon dioxide, CH₄ = methane, N₂O = nitrous oxide, SF₆ = sulfur hexafluoride.

A majority of the carbon dioxide (CO₂) emissions were from generated and purchased electricity (73.7%), while the remaining emissions were from natural gas supply to end-users (26.3%). For methane (CH₄), the majority of emissions were fugitive from natural gas operations (78.1%). Generated and purchased electricity also accounted for all nitrous oxide (N₂O) emissions and all sulfur hexafluoride (SF₆) emissions.

Of the electricity PSE delivered in 2015, 42.0% was generated by PSE and 58.0% was purchased, with 22.7% via firm contracts and 35.3% via non-firm contracts (Figure 7-1). Of the CO₂ emissions associated with electricity, 62.7% were from electricity generated by PSE and 37.3% were from purchased electricity (14.3% via firm contracts and 22.9% via non-firm contracts). The relative amount of GHG emissions from the electricity sources did not align with the amount of power from each electricity source because different electricity generating technologies have different

GHG emission intensities. “Intensity” is the relationship between emissions and production, e.g., metric tons of CO₂ per kilowatt hour (kWh). For instance, about 41.6% of the electricity generated by PSE came from coal combustion, but this electricity source represented about 66.5% of the CO₂ emissions from electricity generated by PSE (Figure 7-3). Hydroelectric plants in the Pacific Northwest accounted for about 64.3% of the firm contract purchased electricity and produced essentially zero GHG emissions (Figure 7-4).

Compared to 2014, the total electricity throughput increased by 13% and the GHG emissions increased by 17% in 2015 (Table 8-3). Within electricity generated by PSE, the combination of decrease in electricity generated from hydro and wind (zero GHG emission intensity) resulted in an increase in GHG emission intensity from 1.46 pounds (lb)/kWh to 1.55 lb/kWh. Within firm and non-firm contract purchased electricity, the combination of increase in firm contracts purchased electricity (also increased GHG emission intensity from 0.12 lb/kWh to 0.64 lb/kWh) and increase in non-firm contracts purchased electricity resulted in an increase in GHG emission intensity from 0.61 lb/kWh to 0.66 lb/kWh. The overall GHG emission intensity from total electricity throughput increased from 0.99 lb/kWh to 1.03 lb/kWh. PSE continues to be moderate in terms of GHG emission intensity as compared to other utilities. Electric generation owned by PSE has a higher CO₂ emission intensity than the national average, but it is moderate in comparison to other large electricity producers. PSE’s overall CO₂ emission intensity, which includes both electricity generated by PSE and purchased by PSE, is lower than the national average, due to the large proportion of hydroelectric generation utilized by PSE.

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.

1.0 INTRODUCTION

This document presents an inventory of greenhouse gas (GHG) emissions from Puget Sound Energy (PSE) operations during the calendar year 2015. 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 (CO₂), methane (CH₄), nitrous oxide (N₂O), and sulfur hexafluoride (SF₆). 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 11 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 2015. 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 compares PSE's GHG emissions to those from other

electric utilities. Section 10.0 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: CO₂, CH₄, N₂O, SF₆, 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 (CO₂e) 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 CO₂e 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 SF₆. The GWP for SF₆ 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 year's 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. However, there have been no amendments to the Washington State GHG reporting requirements since its adoption in 2010. 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. Therefore, amendments to the Washington State GHG reporting requirements are anticipated.

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, CO₂, CH₄, N₂O, and SF₆ 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 CO₂e 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.

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 11.0 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) 2015 Annual Report (Form 10-K) (Puget Energy 2016). The information presented in this document was extracted from the 2015 Annual Report and supplemented by additional information provided by relevant PSE personnel.

4.1.1 *Electrical Operations*

In 2015, PSE supplied electricity to 1,103,635 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 2015, 42.0% of PSE's total electricity was generated by PSE and 58.0% was purchased, with 22.7% via firm contracts and 35.3% via non-firm contracts (Figure 7-1). 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 2015, PSE supplied natural gas to 795,013 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 CO₂ 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 4-1 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, SF₆ emissions from electrical T-D equipment are included. PSE's CH₄ 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 2015. 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 SF₆ emissions from gas-insulated substations, circuit breakers, closed-pressure and hermetically sealed-pressure switchgear, gas-insulated lines containing SF₆, pressurized cylinders, gas carts, electric power transformers, and other containers of SF₆. 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 SF₆ emissions since 2011 to be consistent with the GHG MRR requirements. SF₆ 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 CH₄ at gas-fired turbines. Data regarding the use of PFCs and HFCs in refrigeration equipment and incidental leaks of CH₄ from gas-fired turbines were not available, and these were not considered in this inventory. PFCs and HFCs emissions from refrigeration equipment and CH₄ 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 CO₂ and CH₄ 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. CH₄ 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 CO₂ 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.

4.2.4 *Outside Scope (Emissions from Biomass)*

A small portion of the electricity purchased by PSE is generated through the combustion of biomass, which includes wood waste and municipal waste. Consistent with the GHG Protocol, CO₂ emissions from the combustion of biomass were accounted for separately, as discussed in the introduction of Section 4.2.

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 SF₆ 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 (EPA 2015a) (Table A-3).

PSE's Scope III emissions from non-firm contract purchased electricity were estimated using a lump sum of total non-firm contract purchased electricity and regional average emission factors from the EPA eGRID for CO₂ emissions and the Updated State-level Greenhouse Gas Coefficients for Electricity Generation 1998-2000 (DOE/EIA 2002) for CH₄ and N₂O emissions.

5.3.2 *Natural Gas Supply*

PSE's Scope III CO₂ 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.

5.4

OUTSIDE SCOPE (EMISSIONS FROM BIOMASS)

Emissions from purchased electricity generated through combustion of biomass were calculated using the amount of biomass-generated electricity purchased and AP-42 emission factors.

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 Equivalentents (CO ₂ e)
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 7-1 summarizes the GHG emissions from each source category. A majority of the CO₂ emissions were from generated and purchased electricity (73.7%), while the remaining were from natural gas operations and supply (26.3%). For CH₄, the majority of emissions were from fugitive emissions from natural gas operations (78.1%). Generated and purchased electricity accounted for all N₂O and SF₆ 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 7-2). The GWP is a factor describing the degree of effect a given GHG has on the atmosphere relative to one unit of CO₂. A CO₂e is calculated for each GHG so that GHG emissions can be compared on the same basis. In 2015, CO₂ emissions from generated and purchased electricity were the greatest source of GHGs emitted by PSE on a CO₂ equivalent basis (73.6%), followed by natural gas supply (26.1%) and natural gas operations (0.4%).

Of PSE's electricity throughput (generated and purchased) in 2015, 42.0% was generated by PSE and 58.0% was purchased (22.7% via firm contracts and 35.3% via non-firm contracts) (Figure 7-1). Of the CO₂ emissions that are associated with electricity, 62.7% were from electricity generated by PSE and 37.3% were from electricity purchased (14.3% via firm contracts and 22.9% via non-firm contracts) (Figure 7-1). 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 41.6% of the electricity generated by PSE came from coal combustion (Figure 7-3), 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 CO₂/kWh. Of CO₂ emissions from electricity generated by PSE (direct emissions), about 66.5% were from coal-combustion

generation (Figure 7-3). 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 64.3% of firm contract purchased electricity came from hydroelectric plants in the Pacific Northwest (Figure 7-4). Hydroelectric generation is considered a non-GHG producing generation source in the GHG inventory. Almost all of the CO₂ emissions generated from firm contract purchased electricity come from coal-combustion generated and natural gas generated electric operations.

Third, regional average emission factors 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. Therefore, the emissions associated with non-firm contract purchased electricity were calculated using regional average emission factors, commonly referenced as the "WECC average" (Table 6-5), that generally reflect the suite of generation sources that produced the purchased electricity.

Figure 7-5 shows PSE's generated electricity and firm contract purchased electricity in 2015 by source and the respective CO₂ emissions from each source. The largest source of electricity is coal (36.9%), followed by hydroelectricity (26.8%), natural gas/oil generated electricity (23.6%), wind power generated electricity (11.1%), other or unknown sources (1.0%), biomass (0.4%), and nuclear generated electricity (0.2%). The largest source of CO₂ emissions is from coal-combustion electricity generation (71.2%), followed by natural gas electricity generation (27.5%), biomass electricity generation (0.8%), and other or unknown sources (0.5%).

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 CO₂e 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

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. Trends in PSE's GHG emissions over time are presented in Table 8-1 and Table 8-2. 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.

Compared to 2014 (Table 8-3), PSE's total electricity throughput in 2015 increased by 2,902,247,632 megawatt hours (MWh) (13%). GHG emissions in 2015 increased by 1,789,852 metric tons CO₂e (17%). PSE's electricity generation increased by 524,825,355 MWh (5%); PSE's purchased electricity (firm contract and non-firm contract) increased by 2,377,422,297 MWh (19%). The GHG emission intensity associated with PSE's electricity

production increased from 1.46 lb/kWh to 1.55 lb/kWh. The GHG emission intensity associated with PSE's electricity purchases increased from 0.61 lb/kWh to 0.66 lb/kWh. PSE's overall GHG emission intensity from generated and purchased electricity increased from 0.99 lb/kWh to 1.03 lb/kWh.

Within electricity generated by PSE, the combination of decrease in electricity generated from hydro and wind (zero GHG emission intensity) resulted in an increase in GHG emission intensity from 1.46 lb/kWh to 1.55 lb/kWh. Within firm and non-firm contract purchased electricity, the combination of increase in firm contracts purchased electricity (also increased GHG emission intensity from 0.12 lb/kWh to 0.64 lb/kWh) and increase in non-firm contracts purchased electricity resulted in an increase in GHG emission intensity from 0.61 lb/kWh to 0.66 lb/kWh. The overall GHG emission intensity from total electricity throughput increased from 0.99 lb/kWh to 1.03 lb/kWh.

8.3 CHANGES IN METHODOLOGY

The methodology used in this year's GHG inventory is consistent with that used to prepare the 2014 GHG inventory with some updates in emission factors.

8.3.1 All Emissions

In the 2009 GHG inventory, the GWPs for CH₄ and N₂O 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, CH₄ was updated from 23 to 25, N₂O was updated from 310 to 298, and SF₆ 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 were 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 CH₄ and N₂O 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 CO₂ 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 CO₂ 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 CO₂, CH₄, and N₂O 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 SF₆ 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/ft³) to 1,027 Btu/ft³, 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/ft³, 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/ft³, 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/ft³, as provided in the Natural Gas Annual 2013 (DOE/EIA 2013). In this year’s GHG inventory, the heating value was

updated to 1,044 Btu/ft³, as provided in the Natural Gas Annual 2014 (DOE/EIA 2014).

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 CH₄ and N₂O 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 6-5) 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 CO₂ 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 CO₂ emissions was updated to 0.859 lb/MWh for the Northwest Power Pool (NWPP) WECC Northwest subregion in EPA Seventh Edition eGRID2010 Version 1.0 (EPA 2011).

In the 2012 GHG inventory, the eGRID emission factor for CO₂ 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 CO₂ 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 this year's inventory, the eGRID emission factor for CO₂ 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.

8.3.3.2 *Natural Gas Supply*

PSE's Scope III emissions associated with natural gas supply include CO₂ 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.

The 2016 Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States Report was released in July 2016 through a collaborative effort among Bank of America, Calpine, Entergy, Exelon, Ceres, and the Natural Resources Defense Council (NRDC). The report examines and compares the air pollutant emissions of the 100 largest power producers in the U.S. based on 2014 generation and emissions data that are available to the public through several databases maintained by state and federal agencies.

The CO₂ emission intensities (lb/kWh) published in the 2016 Benchmarking Report and those calculated in this report show good agreement. The 2016 Benchmarking Report indicates that PSE's 2014 CO₂ emission intensities for all generating sources and coal-fired generation are 1.218 lb/kWh and 2.303 lb/kWh, respectively. The CO₂ emission intensities calculated in the 2014 GHG inventory for all generating sources and coal-fired generation were 1.46 lb/kWh and 2.39 lb/kWh, respectively. In this year's GHG inventory, the CO₂ emission intensities calculated for all generating sources and coal-fired generation are 1.55 lb/kWh and 2.47 lb/kWh, respectively (Table 8-3).

Among the 100 largest U.S. electric producers in 2014, PSE ranked 63rd in total generation and 61st in coal-fired generation. For total CO₂ emissions, PSE ranked 64th. In terms of CO₂ emission intensity, PSE ranked 51st in all generating sources. PSE's CO₂ emission intensity from Colstrip, when compared to other utilities' coal-only resources ranked 14th. The intensity ranks above most plants in part because of plant efficiency and in part because of the available energy in the region's coal (Btu/lb). PSE's CO₂ emission intensity was compared to other utilities graphically in Figure 9-1. PSE's emissions from electricity generation are moderate compared to other electric producers. PSE's overall CO₂ emission intensity, which includes both generated and purchased electricity, is lower than the national average, due to the large proportion of hydroelectric power utilized by PSE.

10.0

CONSERVATION PROGRAMS AND GHG EMISSIONS AVOIDED

PSE operates a variety of electric and natural gas conservation programs, which result in significant reductions in demand on electric and natural gas resources. A summary of the programs is included in Table 10-1. These programs led to an estimated savings of 282,600,000 kWh of electricity and 3,242,000 therms of natural gas in 2015. According to PSE Aurora modeling for resource planning purposes, any conserved electricity would most likely be replaced by a marginal plant. A marginal plant in the NWPP is a CCGT rated at approximately 7,000 Btu/kWh.

Using this assumption, these electric conservation measures amounted to avoided emissions of over 96,416 metric tons of CO₂, 0.24 metric tons of CH₄, and 0.19 metric tons of N₂O in 2015. PSE's natural gas conservation measures amounted to an avoidance of emissions of approximately 19.85 metric tons of CH₄ in 2015.

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Appendix A
Tables and Figures

Table 4-1. Calendar Year 2015 Sources of Emissions Accounted**Puget Sound Energy - 2015 Greenhouse Gas Inventory**

Operational Boundary	Greenhouse Gases					
	CO ₂	CH ₄	N ₂ O	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 6-1. Total Emissions by Scope

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Source	Energy Amount (UOM)	Emissions								Emission Intensity			
		CO ₂		CH ₄		N ₂ O		SF ₆		CO ₂ (UOM)	CH ₄ (UOM)	N ₂ O (UOM)	SF ₆ (UOM)
		(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾				
Scope I													
<i>Electric Operations</i>													
Hydro	706,231,308 kWh	0	0%	0	0%	0	0%	0	0%	0 lb/kWh	0 lb/kWh	0 lb/kWh	0 lb/kWh
Coal	4,495,032,000 kWh	4,997,302	67%	545	19%	79	93%	0	0%	2.5 lb/kWh	2.7E-04 lb/kWh	3.9E-05 lb/kWh	0 lb/kWh
Natural Gas/ Oil	3,886,802,483 kWh	2,515,656	33%	47	2%	6.1	7%	0	0%	1.4 lb/kWh	2.7E-05 lb/kWh	3.4E-06 lb/kWh	0 lb/kWh
Wind	1,715,433,188 kWh	0	0%	0	0%	0	0%	0	0%	0 lb/kWh	0 lb/kWh	0 lb/kWh	0 lb/kWh
Electrical Transmission and Distribution Equipment	0 kWh	0	0%	0	0%	0	0%	1.3	100%	NC	NC	NC	NC
Total Scope I - PSE-owned Electric Operations	10,803,498,979 kWh	7,512,958	100%	592	20%	85	100%	1.3	100%	1.5 lb/kWh	0.0001 lb/kWh	0.00002 lb/kWh	2.6E-07 lb/kWh
<i>Natural Gas Operations</i>													
Distribution	791,212,000 thm	72	0%	2,341	80%	0	0%	0	0%	2.0E-04 lb/thm	6.5E-03 lb/thm	0 lb/thm	0 lb/thm
Total Scope I - PSE-owned Natural Gas Operations	791,212,000 thm	72	0%	2341	80%	0	0%	0	0%	0.0002 lb/thm	0.007 lb/thm	0 lb/thm	0 lb/thm
Total Scope I		7,513,031	100%	2,933	100%	85	100%	1.3	100%				
Scope III													
<i>Electric Operations</i>													
Firm Contracts	5,813,567,972 kWh	1,680,718	19%	19	29%	28	26%	0	NC	0.6 lb/kWh	7.E-06 lb/kWh	1.E-05 lb/kWh	0 lb/kWh
Non-Firm Contracts ⁽¹⁾	9,094,697,000 kWh	2,746,437	32%	46	71%	79	74%	0	NC	0.7 lb/kWh	1.E-05 lb/kWh	2.E-05 lb/kWh	0 lb/kWh
Total Scope III - Electricity Purchases	14,908,264,972 kWh	4,427,155	51%	64	100%	107	100%	0	NC	1 lb/kWh	0 lb/kWh	0 lb/kWh	0 lb/kWh
<i>Natural Gas Supply</i>													
Supply to End-Users	787,308,071 thm	4,282,956	49%	0	0%	0	0%	0	NC	12 lb/thm	0 lb/thm	0 lb/thm	0 lb/thm
Total Scope III - Natural Gas Supply	787,308,071 thm	4,282,956	49%	0	0%	0	0%	0	NC	12 lb/thm	0 lb/thm	0 lb/thm	0 lb/thm
Total Scope III		8,710,111	100%	64	100%	107	100%	0	NC				
Outside Scope													
Biomass - Firm Contract Purchases ⁽²⁾	24,067,288 kWh	34,537	100%	0	NC	0	NC	0	NC	3.2 lb/kWh	0 lb/kWh	0 lb/kWh	0 lb/kWh
Total Outside Scope		34,537	100%	0	NC	0	NC	0	NC				

Note(s):

- (1) Non-firm contract purchases do not include "Book Outs" under EITF Issue 03-11.
- (2) Consistent with the GHG Protocol, only CO₂ is accounted separately for biomass generation.
- (3) Percentage of emissions in scope.
- (4) NC = Not calculated.

Table 6-2. Total Emissions by Scope in CO2 Equivalents (CO2e)

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Source	Energy Amount (UOM)	Emissions in CO ₂ Equivalents (CO ₂ e) - 100-Year Timeframe (Tons)										Emission Intensity Total (UOM)
		CO ₂		CH ₄		N ₂ O		SF ₆		Total		
		(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾	
Scope I												
<i>Electric Operations</i>												
Hydro	706,231,308 kWh	0	0%	0	0%	0	0%	0	0%	0	0%	0 lb/kWh
Coal	4,495,032,000 kWh	4,997,302	65%	13,622	0.2%	23,620	0.3%	0	0%	5,034,544	66%	2.5 lb/kWh
Natural Gas/ Oil	3,886,802,483 kWh	2,515,656	33%	1,168	0.02%	1,808	0.02%	0	0%	2,518,632	33%	1.4 lb/kWh
Wind	1,715,433,188 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%	28,666	0.4%	28,666	0.4%	NC
Total Scope I - PSE-owned Electric Operations	10,803,498,979 kWh	7,512,958	98%	14,790	0.2%	25,428	0.3%	28,666	0.4%	7,581,843	99%	1.5 lb/kWh
<i>Natural Gas Operations</i>												
Distribution	791,212,000 thm	72	0.001%	58,537	0.8%	0	0%	0	0%	58,610	0.8%	0.2 lb/thm
Total Scope I - PSE-owned Natural Gas Operations	791,212,000 thm	72	0.001%	58,537	0.8%	0	0%	0	0%	58,610	0.8%	0.2 lb/thm
Total Scope I		7,513,031	98%	73,327	1.0%	25,428	0.3%	28,666	0.4%	7,640,452	100%	
Scope III												
<i>Electric Operations</i>												
Firm Contracts	5,813,567,972 kWh	1,680,718	19%	467	0.01%	8,367	0.1%	0	0%	1,689,552	19%	0.6 lb/kWh
Non-Firm Contracts ⁽¹⁾	9,094,697,000 kWh	2,746,437	31%	1,145	0.01%	23,603	0.3%	0	0%	2,771,185	32%	0.7 lb/kWh
Total Scope III - Electricity Purchases	14,908,264,972 kWh	4,427,155	51%	1,612	0.02%	31,970	0.4%	0	0%	4,460,737	51%	0.7 lb/kWh
<i>Natural Gas Supply</i>												
Supply to End-Users	787,308,071 thm	4,282,956	49%	0	0%	0	0%	0	0%	4,282,956	49%	12.0 lb/thm
Total Scope III - Natural Gas Supply	787,308,071 thm	4,282,956	49%	0	0%	0	0%	0	0%	4,282,956	49%	12.0 lb/thm
Total Scope III		8,710,111	100%	1,612	0.02%	31,970	0.4%	0	0%	8,743,693	100%	
Outside Scope												
Biomass - Firm Contract Purchases ⁽²⁾	24,067,288 kWh	34,537	100%	0	0%	0	0%	0	0%	34,537	100%	3.2 lb/kWh
Total Outside Scope		34,537	100%	0	0%	0	0%	0	0%	34,537	100%	

Data Source:

[1] EPA GHG MRR Subpart A (40 CFR 98.9), Table A-1 (EPA 2015).

Note(s):

- (1) Non-firm contract purchases do not include "Book Outs" under EITF Issue 03-11.
(2) Consistent with the GHG Protocol, only CO₂ is accounted separately for biomass generation.
(3) Percentage of emissions in CO₂e in scope.
(4) NC = Not calculated.

Global Warming Potentials⁽¹⁾:

Time Horizon	CO ₂	CH ₄	N ₂ O	SF ₆
100 years	1	25	298	22,800

Table 6-3. Emissions from PSE-Owned Electric Operations

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Source	Energy Amount ^[1] (kWh)	PSE Share ^[2] (%)	PSE Share of Emissions ⁽¹⁾								Emission Intensity			
			CO ₂ (metric ton) (%) ⁽⁵⁾		CH ₄ (metric ton) (%) ⁽⁵⁾		N ₂ O (metric ton) (%) ⁽⁵⁾		SF ₆ (metric ton) (%) ⁽⁵⁾		CO ₂ (lb/kWh)	CH ₄ (lb/kWh)	N ₂ O (lb/kWh)	SF ₆ (lb/kWh)
Hydro														
Hydro	706,231,308	100%	0	0%	0	0%	0	0%	0	0%	0	0	0	0
Total Hydro	706,231,308		0	0%	0	0%	0	0%	0	0%	0	0	0	0
Coal⁽²⁾														
Colstrip Unit 1	941,354,517	50%	1,075,030	14%	117	20%	17	20%	0	0%	2.5	2.7E-04	4.0E-05	0
Colstrip Unit 2	815,503,483	50%	992,554	13%	103	17%	15	18%	0	0%	2.7	2.8E-04	4.0E-05	0
Colstrip Unit 3	1,363,087,416	25%	1,449,687	19%	159	27%	23	27%	0	0%	2.3	2.6E-04	3.7E-05	0
Colstrip Unit 4	1,375,086,584	25%	1,480,031	20%	166	28%	24	28%	0	0%	2.4	2.7E-04	3.9E-05	0
Total Coal	4,495,032,000		4,997,302	67%	545	92%	79	93%	0	0%	2.5	2.7E-04	3.9E-05	0
Natural Gas/ Oil⁽³⁾														
Crystal Mountain	293,680	100%	252	0%	0.01	0.0%	0.002	0.0%	0	0%	1.9	7.7E-05	1.5E-05	0
Encogen 1	51,720,089	100%	36,196	0%	0.7	0.1%	0.07	0.1%	0	0%	1.5	2.9E-05	2.9E-06	0
Encogen 2	75,975,584	100%	54,672	1%	1.0	0.2%	0.10	0.1%	0	0%	1.6	2.9E-05	2.9E-06	0
Encogen 3	73,921,152	100%	52,103	1%	1.0	0.2%	0.10	0.11%	0	0%	1.6	2.9E-05	2.9E-06	0
Ferndale 1	291,526,969	100%	205,325	3%	3.8	0.64%	0.38	0.45%	0	0%	1.6	2.9E-05	2.9E-06	0
Ferndale 2	290,429,234	100%	199,984	3%	3.7	0.63%	0.37	0.43%	0	0%	1.5	2.8E-05	2.8E-06	0
Frederickson 1	28,704,436	100%	34,045	0%	0.6	0.1%	0.06	0.1%	0	0%	2.6	4.9E-05	4.9E-06	0
Frederickson 2	11,230,964	100%	13,623	0%	0.3	0.0%	0.03	0.0%	0	0%	2.7	5.0E-05	5.1E-06	0
Fredonia 1	65,487,767	100%	51,605	1%	1.0	0.2%	0.1	0.1%	0	0%	1.7	3.3E-05	3.3E-06	0
Fredonia 2	48,203,333	100%	38,087	1%	0.7	0.1%	0.07	0.1%	0	0%	1.7	3.3E-05	3.4E-06	0
Fredonia 3	23,216,313	100%	12,610	0%	0.2	0.04%	0.02	0.03%	0	0%	1.2	2.2E-05	2.2E-06	0
Fredonia 4	24,387,487	100%	13,304	0%	0.2	0.04%	0.02	0.03%	0	0%	1.2	2.2E-05	2.2E-06	0
Frederickson Unit 1	415,454,075	49.85%	247,376	3%	4.6	0.8%	1.8	2.2%	0	0%	1.3	2.4E-05	9.8E-06	0
Goldendale	960,105,000	100%	551,137	7%	10.2	1.7%	1.0	1.2%	0	0%	1.3	2.3E-05	2.3E-06	0
Mint Farm	1,066,468,050	100%	685,082	9%	12.7	2.1%	1.3	1.5%	0	0%	1.4	2.6E-05	2.6E-06	0
Sumas	420,945,050	100%	282,412	4%	5.2	0.9%	0.5	0.6%	0	0%	1.5	2.7E-05	2.7E-06	0
Whitehorn 2	24,818,537	100%	25,007	0%	0.5	0.1%	0.05	0.1%	0	0%	2.2	4.2E-05	4.3E-06	0
Whitehorn 3	13,914,763	100%	12,836	0%	0.2	0.0%	0.03	0.0%	0	0%	2.0	3.9E-05	4.1E-06	0
Total Natural Gas/ Oil	3,886,802,483		2,515,656	33%	47	8%	6.1	7%	0	0%	1.4	2.7E-05	3.4E-06	0
Wind														
Wild Horse	608,885,750	100%	0	0%	0	0%	0	0%	0	0%	0	0	0	0
Lower Snake River	741,767,960	100%	0	0%	0	0%	0	0%	0	0%	0	0	0	0
Hopkins Ridge	364,779,478	100%	0	0%	0	0%	0	0%	0	0%	0	0	0	0
Total Wind	1,715,433,188		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%	1.3	100%	NC	NC	NC	NC
Total Electrical Transmission and Distribution Equipment			0	0%	0	0%	0	0%	1.3	100%	NC	NC	NC	NC
Total PSE-Owned Electric Operations	10,803,498,979		7,512,958	100%	592	100%	85	100%	1.3	100%	1.5	1.2E-04	1.7E-05	2.6E-07

Data Source:

[1] PSE 2015 Summary of Generation (PSE April 2016).

[2] Puget Energy 2015 Form 10-K (Puget Energy 2016).

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 6-4. Emissions from PSE-Owned Natural Gas Operations**Puget Sound Energy - 2015 Greenhouse Gas Inventory**

Emission Source	Count	Emissions ⁽²⁾				Emissions in CO ₂ Equivalents (CO ₂ e) - 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%	0.6	0.03%	0.02	0.00003%	16	0.03%	16	0.03%
Below Grade M&R Station Components 100 - 300 psig	325	0.3	0.5%	11	0.5%	0.3	0.001%	266	0.5%	267	0.5%
Below Grade M&R Station Components < 100 psig	10	0.01	0.01%	0	0.01%	0.01	0.00001%	4	0.01%	4	0.01%
Total Below Grade M&R Station	338	0.4	0%	11	0%	0.4	0%	287	0%	287	0%
Distribution Mains ⁽¹⁾											
Unprotected Steel	0	0	0%	0	0%	0	0%	0	0%	0	0%
Protected Steel	4,119	7.3	10%	236	10%	7.3	0.01%	5,910	10%	5,918	10%
Plastic	8,477	49	67%	1,571	67%	49	0.1%	39,271	67%	39,319	67%
Cast Iron	0	0	0%	0	0%	0	0%	0	0%	0	0%
Total Distribution Mains	12,596	56	77%	1,807	77%	56	0.1%	45,181	77%	45,237	77%
Distribution Services ⁽¹⁾											
Unprotected Steel	0	0	0%	0	0%	0	0%	0	0%	0	0%
Protected Steel	126,244	13	18%	414	18%	13	0.02%	10,351	18%	10,364	18%
Plastic	663,028	3.4	4.6%	109	4.6%	3.4	0.01%	2,718	5%	2,722	5%
Copper	0	0	0%	0	0%	0	0%	0	0%	0	0%
Total Distribution Services	789,272	16	22%	523	22%	16	0.03%	13,069	22%	13,086	22%
Total PSE-Owned Natural Gas Operations		72	100%	2,341	100%	72	0.1%	58,537	100%	58,610	100%

Data Source:

- [1] Subpart W Reporting Form 2015 (PSE December 2015).
[2] PSE 2015 M&R Survey (PSE 2016).
[3] EPA GHG MRR Subpart A (40 CFR 98.9), Table A-1.

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 CO₂e among PSE-owned natural gas operations.
(5) NC = Not calculated.
(6) M&R = Metering-regulating.

Global Warming Potentials ⁽³⁾:

Time Horizon	CO ₂	CH ₄	N ₂ O	SF ₆
100 years	1	25	298	22,800

Table 6-5. Emissions from Non-Firm Contract Purchased Electricity

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Non-Firm Contract Purchased Electricity: 9,094,697,000 kWh

Emission Source	Emissions		
	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)
Non-Firm Contract Purchased Electricity	2,746,437	45.79	79.21

Emission Factors:

Fuel Type	CO ₂ (lb/kWh)	CH ₄ (lb/kWh)	N ₂ O (lb/kWh)
Other ⁽¹⁾	0.666 [1]	1.11E-05 [2]	1.92E-05 [2]

Data Source:

[1] eGRID2012 (EPA October 2015).

[2] Updated State-level Greenhouse Gas Emission Coefficients for Electricity Generation 1998-2000, Table 3 (DOE/EIA April 2002).

Note(s):

(1) Assume other fuel type. See Table A-3.

Table 6-6. Detailed Emissions Calculations

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Source	Energy Amount (kWh)	Total				Coal				Natural Gas				Hydro		Nuclear	
		% of Total Power	% of Generation or Purchase	Total CO ₂ (metric ton)	Total CH ₄ (metric ton)	Total N ₂ O (metric ton)	Total CO ₂ e (metric ton)	% of Generation	Power (kWh)	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	
NON-FIRM CONTRACT PURCHASES																	
> 100,000,000 kWh	10,528,688,000	40.9%	70.5%														
	2,085,606,000	8.1%	14.0%														
	1,563,318,000	6.1%	10.5%														
	1,304,649,000	5.1%	8.7%														
	1,275,174,000	5.0%	8.5%														
	779,739,000	3.0%	5.2%														
	677,785,000	2.6%	4.5%														
	507,518,000	2.0%	3.4%														
	350,294,000	1.4%	2.3%														
	340,839,000	1.3%	2.3%														
	309,247,000	1.2%	2.1%														
	271,759,000	1.1%	1.8%														
	242,781,000	0.9%	1.6%														
	183,085,000	0.7%	1.2%														
	144,388,000	0.6%	1.0%														
	141,462,000	0.5%	0.9%														
	127,355,000	0.5%	0.9%														
	113,998,000	0.4%	0.8%														
	109,691,000	0.4%	0.7%														
< 100,000,000 > 20,000,000 kWh	352,803,000	1.4%	2.4%														
	96,380,000	0.4%	0.6%														
	67,092,000	0.3%	0.4%														
	57,242,000	0.2%	0.4%														
	42,837,000	0.2%	0.3%														
	38,385,000	0.1%	0.3%														
	26,590,000	0.1%	0.2%														
	24,277,000	0.1%	0.2%														
< 20,000,000 kWh > 1,000,000 kWh	151,559,000	0.6%	1.0%														
	18,557,000	0.1%	0.1%														
	15,993,000	0.1%	0.1%														
	15,430,000	0.1%	0.1%														
	14,768,000	0.1%	0.1%														
	14,148,000	0.1%	0.1%														
	12,393,000	0.05%	0.1%														
	12,114,000	0.05%	0.1%														
	10,905,000	0.04%	0.07%														
	10,619,000	0.04%	0.07%														
	10,400,000	0.04%	0.07%														
	5,966,000	0.02%	0.04%														
	5,045,000	0.02%	0.03%														
	2,021,000	0.01%	0.01%														
	2,000,000																
	1,200,000	0.00%	0.01%														
< 1,000,000	4,091,000	0.02%	0.03%														
	990,000	0.004%	0.01%														
	857,000	0.003%	0.006%														
	800,000	0.003%	0.005%														
	800,000	0.003%	0.005%														
	300,000	0.001%	0.002%														
	297,000	0.001%	0.002%														
	67,000	0.000%	0.000%														
	7,000																
	3,000																
	-30,000	-0.0001%	0.000%														
Total Non-Firm Contract Purchases	11,037,141,000	42.9%	73.9%														
Total Firm & Non-Firm Contracts Purchases	16,874,776,260																
OTHER																	
	-1,942,444,000	-7.5%	-13.0%														
	-5,721,875,000	-22.2%	-38.3%														
	435,743,040	1.7%	2.9%														
	-360,113,438	-1.4%	-2.4%														
	75,629,602																
Total "Other" Adjustments	-1,942,444,000																
Total Non-Firm Contract Purchases Less Other Adjustments ^{(1),(2)}	9,094,697,000	35.3%	60.9%	2,746,437	46	79	2,771,952										
Total Firm & Non-Firm Contracts Purchases Less Other Adjustments	14,932,332,260	58.0%	100%														
Total Firm & Non-Firm Contracts Purchases & PSE Generated Less Other Adjustments	25,735,831,239																

Data Source:

[1] 2015 Power Cost Summary (PSE April 2016).

[2] PSE 2015 Colstrip Operating Statistics (PSE 2016).

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 6-6. Detailed Emissions Calculations

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Source	Energy Amount (kWh)	Biomass					Petroleum					Wind		Solar		Other				
		% of Generation	Power (kWh)	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)	% of Generation	Power (kWh)	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)
PSE GENERATION																				
Hydro ^[1]	706,231,308		0	0	0	0		0	0	0	0		0		0		0		0	0
	706,231,308																			
Coal ^[2]	4,495,032,000		0	0	0	0		0	0	0	0		0		0		0		0	0
	941,354,517																			
	815,503,483																			
	1,363,087,416																			
	1,375,086,584																			
Natural Gas/ Oil ^{[1],[3]}	3,886,802,483		0	0	0	0		0	0	0	0		0		0		0		0	0
	293,680																			
	51,720,089																			
	75,975,584																			
	73,921,152																			
	291,526,969																			
	290,429,234																			
	28,704,436																			
	11,230,964																			
	65,487,767																			
	48,203,333																			
	23,216,313																			
	24,387,487																			
	415,454,075																			
	960,105,000																			
	1,066,468,050																			
	420,945,050																			
	24,818,537																			
	13,914,763																			
Wind ^[1]	1,715,433,188		0	0	0	0		0	0	0	0		1,715,433,188		0		0		0	0
	608,885,750											100.00%	608,885,750							
	741,767,960											100.00%	741,767,960							
	364,779,478											100.00%	364,779,478							
Total PSE Generation	10,803,498,979	0%	0	0	0	0	0%	0	0	0	0	15.88%	1,715,433,188	0	0	0%	0	0	0	0
PURCHASES ^[1]																				
FIRM CONTRACT PURCHASES																				
Hydro	3,356,523,745		0	0	0	0		0	0	0	0		0		0		0		0	0
	19,583,703																			
	6,365,997																			
	2,299,343,000																			
	-39,940,000																			
	-82,401,000																			
	1,094,705,000																			
	53,743,000																			
	4,961,196																			
	162,849																			
Wind	130,777,460		0	0	0	0		0	0	0	0		130,777,460		0		0		0	0
	138,036											100.00%	138,036							
	119,141,000											100.00%	119,141,000							
	129,628											100.00%	129,628							
	11,368,796											100.00%	11,368,796							
Solar	84,550		0	0	0	0		0	0	0	0		0		84,550		0		0	0
	22,840													100.00%	22,840					
	61,710													100.00%	61,710					
Other	2,108,361,000		0	0	0	0		0	0	0	0		2,061,504		0		166,855,520	50,387	1	1
	106,200,000													100.00%	106,200,000	32,071	0.5	0.9		
	7,000,000													100.00%	7,000,000	2,114	0.04	0.1		
	343,584,000											0.60%	2,061,504	15.50%	53,255,520	16,082	0.3	0.5		
	400,000													100.00%	400,000	121	0.00	0.00		
	1,651,177,000																			
Biomass	24,067,288		28,923,238	34,537	4	2		0	0	0	0		0		0		0		0	0
	1,859	100.00%	4,697,428	5,609	0.6	0.4														
	4,697,428	100.00%	4,857,809	5,801	0.6	0.4														
	4,857,809	100.00%	4,857,809	5,801	0.6	0.4														
	4,485,200	100.00%	4,485,200	5,356	0.6	0.4														
	4,950,266	100.00%	4,950,266	5,911	0.6	0.4														
	1,619,280	100.00%	1,619,280	1,934	0.2	0.1														
	3,455,446	100.00%	3,455,446	4,126	0.4	0.3														
PURPA Firm Contracts	217,821,217		32,656,923	38,995	4	3		0	0	0	0		0		278,680		0		0	0
	32,656,923	100.00%	32,656,923	38,995	4	3														
	62,833,254																			
	1,087,094																			
	744,320																			
	36,094,142																			
	278,680													100.00%	278,680					
	22,257,174																			
	738,619																			
	52,604,395																			
	8,526,616																			
Total - Firm Contracts	5,837,635,260	1.05%	61,580,161	73,533	8	5	0%	0	0	0	0	2.28%	132,838,964	0	363,230	2.86%	166,855,520	50,387	1	1

Table 6-6. Detailed Emissions Calculations

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Source	Energy Amount (kWh)	Biomass					Petroleum					Wind		Solar		Other				
		% of Generation	Power (kWh)	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)	% of Generation	Power (kWh)	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)
NON-FIRM CONTRACT PURCHASES																				
> 100,000,000 kWh	10,528,688,000																			
	2,085,606,000																			
	1,563,318,000																			
	1,304,649,000																			
	1,275,174,000																			
	779,739,000																			
	677,785,000																			
	507,518,000																			
	350,294,000																			
	340,839,000																			
	309,247,000																			
	271,759,000																			
	242,781,000																			
	183,085,000																			
	144,388,000																			
	141,462,000																			
	127,355,000																			
	113,998,000																			
	109,691,000																			
< 100,000,000 > 20,000,000 kWh	352,803,000																			
	96,380,000																			
	67,092,000																			
	57,242,000																			
	42,837,000																			
	38,385,000																			
	26,590,000																			
	24,277,000																			
< 20,000,000 kWh > 1,000,000 kWh	151,559,000																			
	18,557,000																			
	15,993,000																			
	15,430,000																			
	14,768,000																			
	14,148,000																			
	12,393,000																			
	12,114,000																			
	10,905,000																			
	10,619,000																			
	10,400,000																			
	5,966,000																			
	5,045,000																			
	2,021,000																			
	2,000,000																			
	1,200,000																			
< 1,000,000	4,091,000																			
	990,000																			
	857,000																			
	800,000																			
	800,000																			
	300,000																			
	297,000																			
	67,000																			
	7,000																			
	3,000																			
	-30,000																			
Total Non-Firm Contract Purchases	11,037,141,000																			
Total Firm & Non-Firm Contracts Purchases	16,874,776,260																			
OTHER																				
	-1,942,444,000																			
	-5,721,875,000																			
	435,743,040																			
	-360,113,438																			
	75,629,602																			
Total "Other" Adjustments	-1,942,444,000																			
Total Non-Firm Contract Purchases Less Other Adjustments ^{(1),(2)}	9,094,697,000																			
Total Firm & Non-Firm Contracts Purchases Less Other Adjustments	14,932,332,260																			
Total Firm & Non-Firm Contracts Purchases & PSE Generated Less Other Adjustments	25,735,831,239																			

Data Source:

[1] 2015 Power Cost Summary (PSE April 2016).

[2] PSE 2015 Colstrip Operating Statistics (PSE 2016).

Note(s):

(1) Non-firm contract purchases do not include "Book Outs" under Emerging Issues Task Force Issue Nc

(2) Emissions from non-firm contract purchases calculated via national/ regional emission factors. See T

(3) PSE-Generated gas turbines track diesel fuel emissions under natural gas emissions.

Table 6-6. Detailed Emissions Calculations

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Source	Energy Amount (kWh)	Biomass					Petroleum					Wind		Solar		Other				
		% of Generation	Power (kWh)	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)	% of Generation	Power (kWh)	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)
PSE GENERATION																				
Hydro ^[1]	706,231,308		0	0	0	0		0	0	0	0		0		0		0		0	0
	706,231,308																			
Coal ^[2]	4,495,032,000		0	0	0	0		0	0	0	0		0		0		0		0	0
	941,354,517																			
	815,503,483																			
	1,363,087,416																			
	1,375,086,584																			
Natural Gas/ Oil ^{[1],[3]}	3,886,802,483		0	0	0	0		0	0	0	0		0		0		0		0	0
	293,680																			
	51,720,089																			
	75,975,584																			
	73,921,152																			
	291,526,969																			
	290,429,234																			
	28,704,436																			
	11,230,964																			
	65,487,767																			
	48,203,333																			
	23,216,313																			
	24,387,487																			
	415,454,075																			
	960,105,000																			
	1,066,468,050																			
	420,945,050																			
	24,818,537																			
	13,914,763																			
Wind ^[1]	1,715,433,188		0	0	0	0		0	0	0	0		1,715,433,188		0		0		0	0
	608,885,750											100.00%	608,885,750							
	741,767,960											100.00%	741,767,960							
	364,779,478											100.00%	364,779,478							
Total PSE Generation	10,803,498,979	0%	0	0	0	0	0%	0	0	0	0	15.88%	1,715,433,188	0	0	0%	0	0	0	0
PURCHASES ^[1]																				
FIRM CONTRACT PURCHASES																				
Hydro	3,356,523,745		0	0	0	0		0	0	0	0		0		0		0		0	0
	19,583,703																			
	6,365,997																			
	2,299,343,000																			
	-39,940,000																			
	-82,401,000																			
	1,094,705,000																			
	53,743,000																			
	4,961,196																			
	162,849																			
Wind	130,777,460		0	0	0	0		0	0	0	0		130,777,460		0		0		0	0
	138,036											100.00%	138,036							
	119,141,000											100.00%	119,141,000							
	129,628											100.00%	129,628							
	11,368,796											100.00%	11,368,796							
Solar	84,550		0	0	0	0		0	0	0	0		0		84,550		0		0	0
	22,840													100.00%	22,840					
	61,710													100.00%	61,710					
Other	2,108,361,000		0	0	0	0		0	0	0	0		2,061,504		0		166,855,520	50,387	1	1
	106,200,000													100.00%	106,200,000	32,071	0.5	0.9		
	7,000,000													100.00%	7,000,000	2,114	0.04	0.1		
	343,584,000											0.60%	2,061,504	15.50%	53,255,520	16,082	0.3	0.5		
	400,000													100.00%	400,000	121	0.00	0.00		
	1,651,177,000																			
Biomass	24,067,288		28,923,238	34,537	4	2		0	0	0	0		0		0		0		0	0
	1,859	100.00%	4,697,428	5,609	0.6	0.4														
	4,697,428	100.00%	4,857,809	5,801	0.6	0.4														
	4,857,809	100.00%	4,857,809	5,801	0.6	0.4														
	4,485,200	100.00%	4,485,200	5,356	0.6	0.4														
	4,950,266	100.00%	4,950,266	5,911	0.6	0.4														
	1,619,280	100.00%	1,619,280	1,934	0.2	0.1														
	3,455,446	100.00%	3,455,446	4,126	0.4	0.3														
PURPA Firm Contracts	217,821,217		32,656,923	38,995	4	3		0	0	0	0		0		278,680		0		0	0
	32,656,923	100.00%	32,656,923	38,995	4	3														
	62,833,254																			
	1,087,094																			
	744,320																			
	36,094,142																			
	278,680													100.00%	278,680					
	22,257,174																			
	738,619																			
	52,604,395																			
	8,526,616																			
Total - Firm Contracts	5,837,635,260	1.05%	61,580,161	73,533	8	5	0%	0	0	0	0	2.28%	132,838,964	0	363,230	2.86%	166,855,520	50,387	1	1

Table 6-6. Detailed Emissions Calculations

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Source	Energy Amount (kWh)	Biomass					Petroleum					Wind		Solar		Other				
		% of Generation	Power (kWh)	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)	% of Generation	Power (kWh)	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)
NON-FIRM CONTRACT PURCHASES																				
> 100,000,000 kWh	10,528,688,000																			
	2,085,606,000																			
	1,563,318,000																			
	1,304,649,000																			
	1,275,174,000																			
	779,739,000																			
	677,785,000																			
	507,518,000																			
	350,294,000																			
	340,839,000																			
	309,247,000																			
	271,759,000																			
	242,781,000																			
	183,085,000																			
	144,388,000																			
	141,462,000																			
	127,355,000																			
	113,998,000																			
	109,691,000																			
< 100,000,000 > 20,000,000 kWh	352,803,000																			
	96,380,000																			
	67,092,000																			
	57,242,000																			
	42,837,000																			
	38,385,000																			
	26,590,000																			
	24,277,000																			
< 20,000,000 kWh > 1,000,000 kWh	151,559,000																			
	18,557,000																			
	15,993,000																			
	15,430,000																			
	14,768,000																			
	14,148,000																			
	12,393,000																			
	12,114,000																			
	10,905,000																			
	10,619,000																			
	10,400,000																			
	5,966,000																			
	5,045,000																			
	2,021,000																			
	2,000,000																			
	1,200,000																			
< 1,000,000	4,091,000																			
	990,000																			
	857,000																			
	800,000																			
	800,000																			
	300,000																			
	297,000																			
	67,000																			
	7,000																			
	3,000																			
	-30,000																			
Total Non-Firm Contract Purchases	11,037,141,000																			
Total Firm & Non-Firm Contracts Purchases	16,874,776,260																			
OTHER																				
	-1,942,444,000																			
	-5,721,875,000																			
	435,743,040																			
	-360,113,438																			
	75,629,602																			
Total "Other" Adjustments	-1,942,444,000																			
Total Non-Firm Contract Purchases Less Other Adjustments ^{(1),(2)}	9,094,697,000																			
Total Firm & Non-Firm Contracts Purchases Less Other Adjustments	14,932,332,260																			
Total Firm & Non-Firm Contracts Purchases & PSE Generated Less Other Adjustments	25,735,831,239																			

Data Source:

[1] 2015 Power Cost Summary (PSE April 2016).

[2] PSE 2015 Colstrip Operating Statistics (PSE 2016).

Note(s):

(1) Non-firm contract purchases do not include "Book Outs" under Emerging Issues Task Force Issue No. 03-

(2) Emissions from non-firm contract purchases calculated via national/ regional emission factors. See Table

(3) PSE-Generated gas turbines track diesel fuel emissions under natural gas emissions.

Table 7-1. Total Emissions by Source

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Source	Energy Amount (UOM) (%) ⁽²⁾		Emissions								Emission Intensity			
			CO ₂		CH ₄		N ₂ O		SF ₆		CO ₂ (UOM)	CH ₄ (UOM)	N ₂ O (UOM)	SF ₆ (UOM)
			(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾				
Generated and Purchased Electricity														
<i>PSE-Owned Electric Operations</i>														
Hydro	706,231,308 kWh	2.7%	0	0%	0	0%	0	0%	0	0%	0 lb/kWh	0 lb/kWh	0 lb/kWh	0 lb/kWh
Coal	4,495,032,000 kWh	17.5%	4,997,302	30.7%	545	18.2%	79	41.2%	0	0%	2.5 lb/kWh	2.7E-04 lb/kWh	3.9E-05 lb/kWh	0 lb/kWh
Natural Gas/ Oil	3,886,802,483 kWh	15.1%	2,515,656	15.5%	47	1.6%	6.1	3.1%	0	0%	1.4 lb/kWh	2.7E-05 lb/kWh	3.4E-06 lb/kWh	0 lb/kWh
Wind	1,715,433,188 kWh	6.7%	0	0%	0	0%	0	0%	0	0%	0 lb/kWh	0 lb/kWh	0 lb/kWh	0 lb/kWh
Electrical Transmission and Distribution Equipment	0 kWh	0%	0	0%	0	0%	0	0%	1.26	100%	NC	NC	NC	NC
Total - PSE-owned Electric Operations	10,803,498,979 kWh	42.0%	7,512,958	46.2%	592	19.7%	85	44.3%	1.26	100%	1.5 lb/kWh	1.2E-04 lb/kWh	1.7E-05 lb/kWh	2.6E-07 lb/kWh
<i>Firm & Non-Firm Contracts Purchases</i>														
Firm Contracts	5,837,635,260 kWh	22.7%	1,715,255	10.6%	19	0.6%	28	14.6%	0	0%	0.6 lb/kWh	7.1E-06 lb/kWh	1.1E-05 lb/kWh	0 lb/kWh
Non-Firm Contracts ⁽¹⁾	9,094,697,000 kWh	35.3%	2,746,437	16.9%	46	1.5%	79	41.1%	0	0%	0.7 lb/kWh	1.1E-05 lb/kWh	1.9E-05 lb/kWh	0 lb/kWh
Total - Firm & Non-Firm Contracts Purchases	14,932,332,260 kWh	58.0%	4,461,692	27.4%	64	2.2%	107	55.7%	0	0%	0.7 lb/kWh	9.5E-06 lb/kWh	1.6E-05 lb/kWh	0 lb/kWh
Total - Generated and Purchased Electricity	25,735,831,239 kWh	100%	11,974,650	73.7%	656	21.9%	193	100%	1.26	100%	1.0 lb/kWh	5.6E-05 lb/kWh	1.6E-05 lb/kWh	0 lb/kWh
Natural Gas Operations														
<i>Distribution and Storage of PSE-owned Natural Gas Operations</i>														
Distribution	791,212,000 thm	100%	72	0.0004%	2,341	78.1%	0	0%	0	0%	2.0E-04 lb/thm	0.01 lb/thm	0 lb/thm	0 lb/thm
Total - Natural Gas Operations	791,212,000 thm	100%	72	0.0004%	2,341	78.1%	0	0%	0	0%	2.0E-04 lb/thm	0.01 lb/thm	0 lb/thm	0 lb/thm
Natural Gas Supply														
<i>Supply to End-Users</i>														
	787,308,071 thm	100%	4,282,956	26.3%	0	0%	0	0%	0	0%	12 lb/thm	0 lb/thm	0 lb/thm	0 lb/thm
Total - Natural Gas Supply	787,308,071 thm	100%	4,282,956	26.3%	0	0%	0	0%	0	0%	12 lb/thm	0 lb/thm	0 lb/thm	0 lb/thm
Emissions from All Sources			16,257,679	100%	2,998	100%	193	100%	1.26	100%				

Note(s):

- (1) Non-firm contract purchases do not include "Book Outs" under EITF Issue 03-11. "Book outs" are included in Sales to Other Utilities and Marketers.
- (2) Percentage of energy within source category.
- (3) Percentage of emissions within source category.
- (4) NC = Not calculated.

Table 7-2. Total Emissions by Source in CO₂ Equivalents (CO₂e)

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Source	Energy Amount (UOM) (%) ⁽²⁾		Emissions in CO ₂ Equivalents (CO ₂ e) - 100-Year Timeframe (Tons)								Emission Intensity		
			CO ₂		CH ₄		N ₂ O		SF ₆		Total		Total (UOM)
			(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾	(metric ton)	(%) ⁽³⁾	
Generated and Purchased Electricity													
<i>PSE-Owned Electric Operations</i>													
Hydro	706,231,308 kWh	2.7%	0	0%	0	0%	0	0%	0	0%	0	0%	0 lb/kWh
Coal	4,495,032,000 kWh	17.5%	4,997,302	30.4%	13,622	0.1%	23,620	0.1%	0	0%	5,034,544	30.7%	2.5 lb/kWh
Natural Gas/ Oil	3,886,802,483 kWh	15.1%	2,515,656	15.3%	1,168	0.007%	1,808	0.01%	0	0%	2,518,632	15.3%	1.4 lb/kWh
Wind	1,715,433,188 kWh	6.7%	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%	28,666	0.17%	28,666	0.175%	NC
Total - PSE-owned Electric Operations	10,803,498,979 kWh	42.0%	7,512,958	45.8%	14,790	0.1%	25,428	0.2%	28666	0.17%	7,581,843	46.2%	1.5 lb/kWh
<i>Firm & Non-Firm Contracts Purchases</i>													
Firm Contracts	5,837,635,260 kWh	22.7%	1,715,255	10.4%	467	0.003%	8,367	0.05%	0	0%	1,724,089	10.5%	0.7 lb/kWh
Non-Firm Contracts ⁽¹⁾	9,094,697,000 kWh	35.3%	2,746,437	16.7%	1,145	0.01%	23,603	0.1%	0	0%	2,771,185	16.9%	0.7 lb/kWh
Total - Firm & Non-Firm Contracts Purchases	14,932,332,260 kWh	58.0%	4,461,692	27.2%	1,612	0.0%	31,970	0.2%	0	0%	4,495,274	27.4%	0.7 lb/kWh
Total - Generated and Purchased Electricity	25,735,831,239 kWh	100%	11,974,650	72.9%	16,402	0.1%	57,398	0.3%	28666	0.17%	12,077,117	73.6%	1.0 lb/kWh
Natural Gas Operations													
<i>Distribution and Storage of PSE-owned Natural Gas Operations</i>													
Distribution	791,212,000 thm	100%	72	0.000%	58,537	0.4%	0	0%	0	0%	58,610	0.4%	0.2 lb/thm
Total - Natural Gas Operations	791,212,000 thm	100%	72	0.000%	58,537	0.4%	0	0%	0	0%	58,610	0.4%	0.2 lb/thm
Natural Gas Supply													
<i>Supply to End-Users</i>	787,308,071 thm	100%	4,282,956	26.1%	0	0%	0	0%	0	0%	4,282,956	26.1%	12 lb/thm
Total - Natural Gas Supply	787,308,071 thm	100%	4,282,956	26.1%	0	0%	0	0%	0	0%	4,282,956	26.1%	12 lb/thm
Emissions from All Sources			16,257,679	99.0%	74,940	0.5%	57,398	0.3%	28,666	0.17%	16,418,682	100%	NC

Data Source:

[1] EPA GHG MRR Subpart A (40 CFR 98.9), Table A-1 (EPA 2014).

Note(s):

- (1) Non-firm contract purchases do not include "Book Outs" under EITF Issue 03-11. "Book outs" are included in Sales to Other Utilities and Marketers.
(2) Percentage of energy within source categories.
(3) Percentage of total CO₂e among all sources.
(4) NC = Not calculated.

Global Warming Potentials⁽¹⁾:

Time Horizon	CO ₂	CH ₄	N ₂ O	SF ₆
100 years	1	25	298	22,800

Table 8-1. Emissions Comparison in CO2 Equivalents (CO2e) for the Past Five Years

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Source	2015					2014					2013					2012					2011								
	Energy Amount		Emissions CO ₂ e		Emission Intensity (lb/kWh)	Energy Amount		Emissions CO ₂ e		Emission Intensity (lb/kWh)	Energy Amount		Emissions CO ₂ e		Emission Intensity (lb/kWh)	Energy Amount		Emissions CO ₂ e		Emission Intensity (lb/kWh)	Energy Amount		Emissions CO ₂ e		Emission Intensity (lb/kWh)				
	(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾		(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾		(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾		(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾		(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾		(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾
Generated and Purchased Electricity																													
<i>PSE-Owned Electric Operations</i>																													
Hydro	706,231,308	3%	0	0%	0	1,000,200,655	4%	0	0%	0	837,569,302	3%	0	0%	0	746,739,664	3%	0	0%	0	683,977,604	3%	0	0%	0				
Coal	4,495,032,000	17%	5,033,316	42%	2.47	4,509,567,000	20%	4,888,864	48%	2.39	4,346,208,000	18%	4,703,184	43%	2.39	3,809,524,012	15%	4,134,519	41%	2.39	4,556,429,000	17%	4,533,837	43%	2.19				
Natural Gas/ Oil	3,886,802,483	15%	2,518,518	21%	1.43	2,793,152,355	12%	1,922,244	19%	1.52	3,637,675,938	15%	2,430,357	22%	1.47	1,758,794,382	7%	1,329,713	13%	1.67	1,243,003,923	5%	801,936	8%	1.42				
Wind	1,715,433,188	7%	0	0%	0	1,975,753,634	9%	0	0%	0	1,882,600,192	8%	0	0%	0	1,822,813,069	7%	0	0%	0	1,163,877,414	4%	0	0%	0				
Electrical Transmission and Distribution Equipment	0	0%	30,049	0.2%	NC	0	0%	13,876	0.10%	NC	0	0%	3,187	0.03%	NC	0	0%	-108	-0.001%	NC	0	0%	0	0%	NC				
Total - PSE-owned Electric Operations	10,803,498,979	42%	7,581,883	63%	1.55	10,278,673,644	45%	6,824,985	66.0%	1.46	10,704,053,432	44%	7,136,728	65.6%	1.47	8,137,871,127	33%	5,464,124	55%	1.48	7,647,287,941	29%	5,335,773	51%	1.54				
<i>Firm & Non-Firm Contracts Purchases</i>																													
Firm Contracts	5,595,746,755	22%	1,627,421	13%	0.64	4,203,095,541	18%	235,440	2.0%	0.12	4,508,437,754	18%	216,090	2.0%	0.11	5,929,503,545	24%	478,431	5%	0.18	7,515,378,308	28%	458,542	4%	0.13				
PURPA Purchases	217,821,217	1%	61,601	0.5%	0.62	229,617,559	1%	73,987	0.7%	0.71	165,957,547	1%	26,086	0.2%	0.35	557,023,943	2%	224,302	2%	0.89	1,480,982,082	6%	755,588	7%	1.12				
Non-Firm Contracts ⁽¹⁾	9,094,697,000	35%	2,771,952	23%	0.67	8,097,243,000	35%	3,117,417	30%	0.85	8,986,584,040	37%	3,459,811	32%	0.85	10,112,471,880	41%	3,786,077	38%	0.83	9,858,682,280	37%	3,868,055	37%	0.86				
Biomass	24,067,288	0.1%	35,329	0.3%	3.24	24,953,863	0.1%	36,506	0.4%	3.23	27,963,339	0.1%	39,198	0.4%	3.09	21,142,417	0.09%	25,825	0.3%	2.69	16,299,811	0.06%	13,938	0.1%	1.89				
Interchange/ Optimization In	- not accounted for separately -					- not accounted for separately -					- not accounted for separately -					- not accounted for separately -					- not accounted for separately -								
Total - Firm & Non-Firm Contracts Purchases	14,932,332,260	58%	4,496,304	37%	0.66	12,554,909,963	55%	3,463,350	34%	0.61	13,688,942,680	56%	3,741,186	34%	0.60	16,620,141,785	67%	4,514,635	45%	0.60	18,871,342,481	71%	5,096,123	49%	0.60				
Total - Generated and Purchased Electricity	25,735,831,239	100%	12,078,187	100%	1.03	22,833,583,607	100%	10,288,335	100%	0.99	24,392,996,112	100%	10,877,914	100%	0.98	24,758,012,912	100%	9,978,760	100%	0.89	26,518,630,422	100%	10,431,896	100%	0.87				

Note(s):
 (1) Non-firm contract purchases do not include "Book Outs" under EITF Issue 03-11. "Book outs" are included in Sales to Other Utilities and Marketers.
 (2) Consistent with the GHG Protocol, only CO₂ is accounted separately for biomass generation.
 (3) NC = Not calculated.
 (4) Percentage of energy among total generated and purchased electricity.
 (5) Percentage of emissions among total generated and purchased electricity.

Table 8-2. Emissions Comparison - 2005 through 2015

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Source	2015					2014					2013					2012					2011				
	Energy Amount		Emissions CO ₂		Emission Intensity	Energy Amount		Emissions CO ₂		Emission Intensity	Energy Amount		Emissions CO ₂		Emission Intensity	Energy Amount		Emissions CO ₂		Emission Intensity	Energy Amount		Emissions CO ₂		Emission Intensity
	(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾		(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾		(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾		(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾		(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾	
Generated and Purchased Electricity																									
<i>PSE-Owned Electric Operations</i>																									
Hydro	706,231,308	3%	0	0%	0	1,000,200,655	4%	0	0%	0	837,569,302	3%	0	0%	0	746,739,664	3%	0	0%	0	683,977,604	3%	0	0%	0
Coal	4,495,032,000	17%	4,997,302	42%	2.45	4,509,567,000	20%	4,853,729	48%	2.37	4,346,208,000	18%	4,667,514	43%	2.37	3,809,524,012	15%	4,107,969	41%	2.38	4,556,429,000	17%	4,499,457	43%	2.18
Natural Gas/ Oil	3,886,802,483	15%	2,515,656	21%	1.43	2,793,152,355	12%	1,920,384	19%	1.52	3,637,675,938	15%	2,428,006	22%	1.47	1,758,794,382	7%	1,328,010	13%	1.66	1,243,003,923	5%	801,158	8%	1.42
Wind	1,715,433,188	7%	0	0%	0	1,975,753,634	9%	0	0%	0	1,882,600,192	8%	0	0%	0	1,822,813,069	7%	0	0%	0	1,163,877,414	4%	0	0%	0
Electrical Transmission and Distribution Equipment	0	0%	0	0%	NC	0	0%	0	0%	NC	0	0%	0	0%	NC	0	0%	0	0%	NC	0	0%	0	0%	NC
Total - PSE-owned Electric Operations	10,803,498,979	42%	7,512,958	63%	1.53	10,278,673,644	45%	6,774,113	66%	1.45	10,704,053,432	44%	7,095,520	66%	1.46	8,137,871,127	33%	5,435,979	55%	1.47	7,647,287,941	29%	5,300,614	51%	1.53
<i>Firm & Non-Firm Contracts Purchases</i>																									
Firm Contracts	5,595,746,755	22%	1,620,095	14%	0.64	4,203,095,541	18%	234,099	2%	0.12	4,508,437,754	18%	214,518	2%	0.10	5,929,503,545	24%	474,849	5%	0.18	7,515,378,308	28%	455,265	4%	0.13
PURPA Purchases	217,821,217	1%	60,623	1%	0.61	229,617,559	1%	72,871	1%	0.70	165,957,547	1%	25,950	0%	0.34	557,023,943	2%	223,437	2%	0.88	1,480,982,082	6%	752,433	7%	1.12
Non-Firm Contracts ⁽¹⁾	9,094,697,000	35%	2,746,437	23%	0.67	8,097,243,000	35%	3,094,700	30%	0.84	8,986,584,040	37%	3,434,599	32%	0.84	10,112,471,880	41%	3,757,706	38%	0.82	9,858,682,280	37%	3,840,396	37%	0.86
Biomass	24,067,288	0.1%	34,537	0.3%	3.16	24,953,863	0.1%	35,688	0.3%	3.15	27,963,339	0.1%	38,320	0.4%	3.02	21,142,417	0.09%	25,246	0.3%	2.63	16,299,811	0.06%	13,626	0.1%	1.84
Interchange/ Optimization In	- not accounted for separately -					- not accounted for separately -					- not accounted for separately -					- not accounted for separately -									
Total - Firm & Non-Firm Contracts Purchases	14,932,332,260	58%	4,461,692	37%	0.66	12,554,909,963	55%	3,437,358	34%	0.60	13,688,942,680	56%	3,713,386	34%	0.60	16,620,141,785	67%	4,481,237	45%	0.59	18,871,342,481	71%	5,061,720	49%	0.59
Total - Generated and Purchased Electricity	25,735,831,239	100%	11,974,650	100%	1.03	22,833,583,607	100%	10,211,471	100%	0.99	24,392,996,112	100%	10,808,906	100%	0.98	24,758,012,912	100%	9,917,217	100%	0.88	26,518,630,422	100%	10,362,335	100%	0.86

Emission Source	2010					2009					2008					2007					2006				
	Energy Amount		Emissions CO ₂		Emission Intensity	Energy Amount		Emissions CO ₂		Emission Intensity	Energy Amount		Emissions CO ₂		Emission Intensity	Energy Amount		Emissions CO ₂		Emission Intensity	Energy Amount		Emissions CO ₂		Emission Intensity
	(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾		(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾		(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾		(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾		(kWh)	(%) ⁽⁴⁾	(metric ton)	(%) ⁽⁵⁾	
Generated and Purchased Electricity																									
<i>PSE-Owned Electric Operations</i>																									
Hydro	929,596,698	4%	0	0%	0	987,779,034	4%	0	0%	0	974,924,000	4%	0	0%	0	1,154,233,830	5%	0	0%	0	949,276,360	4%	0	0%	0
Coal	5,650,381,500	22%	5,527,800	47%	2.16	4,788,435,750	17%	4,770,668	41%	2.20	5,516,688,000	22%	5,561,734	51%	2.22	5,142,912,000	20%	5,742,218	49%	2.46	4,800,028,000	19%	5,368,465	44%	2.47
Natural Gas/ Oil	2,754,472,071	11%	1,622,754	14%	1.30	4,363,146,050	16%	1,752,835	15%	0.89	2,269,586,297	9%	828,271	8%	0.80	1,310,625,020	5%	507,775	4%	0.85	723,190,270	3%	307,204	3%	0.94
Wind	990,925,943	4%	0	0%	0	946,494,138	3%	0	0%	0	1,106,780,000	4%	0	0%	0	1,015,323,546	4%	0	0%	0	372,828,350	1%	0	0%	0
Electrical Transmission and Distribution Equipment	0	0%	NC	NC	NC	0	0%	0	0%	0	0	0%	0	0%	0	- not presented in report -				- not presented in report -					
Total - PSE-owned Electric Operations	10,325,376,212	41%	7,150,554	60%	1.53	11,085,854,972	40%	6,523,504	56%	1.30	9,867,978,297	39%	6,390,005	58%	1.43	8,623,094,396	34%	6,249,992	53%	1.60	6,845,322,980	27%	5,675,669	46%	1.83
<i>Firm & Non-Firm Contracts Purchases</i>																									
Firm Contracts	6,894,780,000	27%	1,162,048	10%	0.37	6,138,673,570	22%	596,901	5%	0.21	6,918,194,390	27%	789,075	7%	0.25	7,058,967,440	28%	739,219	6%	0.23	6,926,996,520	28%	724,305	6%	0.23
PURPA Purchases	2,036,029,490	8%	1,095,233	9%	1.19	2,140,182,620	8%	1,171,620	10%	1.21	1,790,648,482	7%	961,638	9%	1.18	2,285,841,710	9%	1,256,965	11%	1.21	2,689,484,164	11%	1,517,860	12%	1.24
Non-Firm Contracts ⁽¹⁾	6,226,857,600	24%	2,425,639	20%	0.86	8,106,128,920	30%	3,317,461	29%	0.90	6,969,392,040	27%	2,852,247	26%	0.90	7,384,691,000	29%	3,439,577	29%	1.03	8,569,778,912	34%	4,353,649	35%	1.12
Biomass	11,149,693	0.04%	9,321	0.08%	1.84	6,904,930	0.03%	8,856	0.08%	2.83	2,232,000	0.01%	2,863	0.03%	2.83	2,091,600	0.01%	2,683	0.02%	2.83	1,823,280	0.01%	726	0.01%	0.88
Interchange/ Optimization In	- not accounted for separately -					- not accounted for separately -					- not accounted for separately -					- not accounted for separately -									
Total - Firm & Non-Firm Contracts Purchases	15,168,816,783	59%	4,692,240	40%	0.68	16,391,890,040	60%	5,094,837	44%	0.69	15,680,466,912	61%	4,605,823	42%	0.65	16,731,591,750	66%	5,438,444	47%	0.72	18,188,082,876	73%	6,596,539	54%	0.80
Total - Generated and Purchased Electricity	25,494,192,995	100%	11,842,795	100%	1.02	27,477,745,012	100%	11,618,340	100%	0.93	25,548,445,209	100%	10,995,828	100%	0.95	25,354,686,146	100%	11,688,436	100%	1.02	25,033,405,856	100%	12,272,208	100%	1.08

Note(s):
 (1) Non-firm contract purchases do not include "Book Outs" under EITF Issue 03-11. "Book outs" are included in Sales to Other Utilities and Marketers.
 (2) Consistent with the GHG Protocol, only CO₂ is accounted separately for biomass generation.
 (3) NC = Not calculated.
 (4) Percentage of energy among total generated and purchased electricity.
 (5) Percentage of emissions among total generated and purchased electricity.

Table 8-3. Emissions Comparison in CO2 Equivalents (CO2e) - 2015 vs. 2014

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Source	2015 vs. 2014					2015					2014				
	Energy Amount		Emissions CO ₂ e		Emission Intensity (lb/kWh)	Energy Amount		Emissions CO ₂ e		Emission Intensity (lb/kWh)	Energy Amount		Emissions CO ₂ e		Emission Intensity (lb/kWh)
	(kWh)	(%) ⁽³⁾	(metric ton)	(%) ⁽⁴⁾		(kWh)	(%) ⁽³⁾	(metric ton)	(%) ⁽⁴⁾		(kWh)	(%) ⁽³⁾	(metric ton)	(%) ⁽⁴⁾	
Generated and Purchased Electricity															
<i>PSE-Owned Electric Operations</i>															
Hydro	-293,969,347	-29%	0	NA	0	706,231,308	3%	0	0%	0	1,000,200,655	4%	0	0%	0
Coal	-14,535,000	-0.3%	144,452	3%	0.079	4,495,032,000	17%	5,033,316	42%	2.47	4,509,567,000	20%	4,888,864	48%	2.39
Natural Gas/ Oil	1,093,650,128	39%	596,274	31%	-0.09	3,886,802,483	15%	2,518,518	21%	1.43	2,793,152,355	12%	1,922,244	19%	1.52
Wind	-260,320,446	-13%	0	NA	0	1,715,433,188	7%	0	0%	0	1,975,753,634	9%	0	0%	0
Electrical Transmission and Distribution Equipment	0	NA	16,173	117%	NC	0	0%	30,049	0.2%	NC	0	0%	13,876	0.10%	NC
Total - PSE-owned Electric Operations	524,825,335	5%	756,898	11%	0.09	10,803,498,979	42%	7,581,883	63%	1.55	10,278,673,644	45%	6,824,985	66%	1.46
<i>Firm & Non-Firm Contracts Purchases</i>															
Firm Contracts	1,392,651,214	33%	1,391,981	591%	0.52	5,595,746,755	22%	1,627,421	13%	0.64	4,203,095,541	18%	235,440	2%	0.12
PURPA Purchases	-11,796,342	-5%	-12,386	-17%	-0.09	217,821,217	1%	61,601	1%	0.62	229,617,559	1%	73,987	1.0%	0.71
Non-Firm Contracts ⁽¹⁾	997,454,000	12%	-345,465	-11%	-0.2	9,094,697,000	35%	2,771,952	23%	0.67	8,097,243,000	35%	3,117,417	30%	0.85
Biomass	-886,575	-4%	-1,177	-3%	0.01	24,067,288	0.1%	35,329	0.3%	3.24	24,953,863	0.1%	36,506	0.4%	3.23
Interchange/ Optimization In			- not accounted for separately -					- not accounted for separately -					- not accounted for separately -		
Total - Firm & Non-Firm Contracts Purchases	2,377,422,297	19%	1,032,954	30%	0.05	14,932,332,260	58%	4,496,304	37%	0.66	12,554,909,963	55%	3,463,350	34%	0.61
Total - Generated and Purchased Electricity	2,902,247,632	13%	1,789,852	17%	0.04	25,735,831,239	100%	12,078,187	100%	1.03	22,833,583,607	100%	10,288,335	100%	0.99

Note(s):

- (1) Non-firm contract purchases do not include "Book Outs" under EITF Issue 03-11. "Book outs" are included in Sales to Other Utilities and Marketers.
- (2) Consistent with the GHG Protocol, only CO₂ is accounted separately for biomass generation.
- (3) Percentage of energy among total generated and purchased electricity.
- (4) Percentage of emissions among total generated and purchased electricity.
- (5) NA = Not applicable.
- (6) NC = Not calculated.

Table 10-1. Emissions Avoided**Puget Sound Energy - 2015 Greenhouse Gas Inventory****1. Electric Demand-Side Reduction**Annual Conservation: 282,600,000 kWh [3]

Source of Emissions Savings	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)
Electricity	96,416	0.24	0.19

Emission Factors

Fuel Type	CO ₂ (lb/kWh)	CH ₄ (lb/kWh)	N ₂ O (lb/kWh)
Natural Gas CCGT ⁽¹⁾	0.752 [1]	1.85E-06 [2]	1.50E-06 [2]

2. Natural Gas Conservation ProgramsAnnual Conservation: 3,242,000 thm [3]Natural Gas Emissions: 11,347 thm
1,086,877 ft³

Methane Emissions: 19.8 metric ton

Source of Emissions Savings	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)
Natural Gas	0	19.85	0

Calculation Inputs:

Parameter	Value	(UOM)
Emission rate from Distribution	0.35%	of throughput [4]
Emission rate from Storage Facilities	5.80E-03	Gg methane / 10 ⁶ m ³ gas stored [4]
Heating Value of Natural Gas Delivered to Consumers in Washington	1,044	Btu/ft ³ [5]
Energy Content of Natural Gas	100,000	Btu/thm
Density of Methane	0.6785	kg/m ³
Methane in Natural Gas	95%	
Unit Conversion	35.3	ft ³ /m ³

Total Emissions Reductions From Conservation Programs

Source of Emissions Savings	CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)
Electricity and Natural Gas	96,416	20.08	0.19

Data Source:

- [1] Voluntary Reporting of Greenhouse Gases Program – Fuel and Energy Source Codes and Emission Coefficients (DOE/EIA March 2009).
 [2] Updated State-level Greenhouse Gas Emission Coefficients for Electricity Generation 1998-2000, Table 3 (DOE/EIA April 2002).
 [3] PSE 2015 Annual Report of Energy Conservation Accomplishments, Table I-1 (PSE 2016).
 [4] Methane Emissions from the Natural Gas Industry, Volume 2: Technical Report, Table 4-3 (EPA/GRI June 1996).
 [5] Natural Gas Annual 2014, Table 16 (DOE/EIA Oct 2014).

Note(s):

- (1) Emissions estimated based on average CCGT emission rates.

Table A-1. Emissions from PSE-Owned Electric Operations: Colstrip**Puget Sound Energy - 2015 Greenhouse Gas Inventory**

Unit ID	Unit Type ^[1]	Capacity ^[1] (MW)	PSE Share ^[1]	Fuel Type ^[2]	Fuel Usage ^[2] (UOM)	HHV ^{[1],[2]} (UOM)	HI ^{[2],[3]} (UOM)	PSE Share of Emissions ^[4]		
								CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)
Colstrip Unit 1	Coal	307	50%	Coal LPG	1,219,499 short ton 441,656 gal	17.39 MMBtu/ton 0.09 MMBtu/gallon	21,207,487 MMBtu 40,191 MMBtu	1,075,030 {1}	116.70 {2}	16.98 {2}
Colstrip Unit 2	Coal	307	50%	Coal LPG	1,074,833 short ton 402,250 gal	17.39 MMBtu/ton 0.09 MMBtu/gallon	18,691,705 MMBtu 36,605 MMBtu	992,554 {1}	102.86 {2}	14.96 {2}
Colstrip Unit 3	Coal	370	25%	Coal Distillate Fuel Oil	3,436,820 short ton 180,078 gal	16.82 MMBtu/ton 0.14 MMBtu/gallon	57,799,860 MMBtu 24,851 MMBtu	1,449,687 {1}	158.97 {2}	23.12 {2}
Colstrip Unit 4	Coal	370	25%	Coal Distillate Fuel Oil	3,596,329 short ton 160,586 gal	16.82 MMBtu/ton 0.14 MMBtu/gallon	60,482,456 MMBtu 22,161 MMBtu	1,480,031 {1}	166.34 {2}	24.20 {2}
Total								4,997,302	545	79

Emission Factors:

Fuel Type	CH ₄ (kg/MMBtu)	N ₂ O (kg/MMBtu)
Coal	1.1E-02 [4]	1.6E-03 [4]
Propane	3.0E-03 [4]	6.0E-04 [4]
Distillate Fuel Oil	3.0E-03 [4]	6.0E-04 [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).

Data Source:

[1] Puget Energy 2015 Form 10-K (Puget Energy 2016).

[2] 2015 PSE Colstrip Emission Inventory Data Report.

[3] PSE 2015 Colstrip Operating Statistics (PSE 2016).

[4] EPA GHG MRR Subpart C (40 CFR 98.38), 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 the WRI/WBCSD GHG Protocol equity share method.

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

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Unit ID	Unit Type ^[1]	Capacity ^[1] (MW)	PSE Share ^[1]	Fuel Type ^[2]	Fuel Usage ^[2] (UOM)	HHV ^{[2],[5],[1]} (UOM)	HI ^{[2],[3]} (UOM)	PSE Share of Emissions ^[4]		
								CO ₂ (metric ton)	CH ₄ (metric ton)	N ₂ O (metric ton)
Crystal Mountain	Internal Combustion	3	100%	Distillate Fuel Oil No. 2	24,686 gal	0.138 MMBtu/gal	NR ⁽³⁾	251.96 ⁽³⁾	0.010 ⁽⁵⁾	0.0020 ⁽⁵⁾
Encogen 1	Natural gas cogeneration	165	100%	Natural Gas	623,411,266 scf ⁽³⁾	NR ⁽³⁾	671,028 MMBtu	36,196.30 ^{(1), [3]}	0.67 ⁽²⁾	0.07 ⁽²⁾
				Distillate Fuel Oil No. 2	7,054 gal ⁽³⁾					
Encogen 2	Natural gas cogeneration			Natural Gas	943,061,080 scf ⁽³⁾	NR ⁽³⁾	1,013,869 MMBtu	54,672.20 ^{(1), [3]}	1.01 ⁽²⁾	0.10 ⁽²⁾
				Distillate Fuel Oil No. 2	4,048 gal					
Encogen 3	Natural gas cogeneration			Natural Gas	899,234,534 scf ⁽³⁾	NR ⁽³⁾	966,388 MMBtu	52,102.89 ^{(1), [3]}	0.97 ⁽²⁾	0.10 ⁽²⁾
				Distillate Fuel Oil No. 2	1,118 gal					
Ferndale 1	Natural gas combined cycle	253	100%	Natural Gas	3,531,161,000 scf ⁽³⁾	NR ⁽³⁾	3,808,333 MMBtu	205,325.50 ^{(1), [3]}	3.81 ⁽²⁾	0.38 ⁽²⁾
				Distillate Fuel Oil No. 2	2,840 gal					
Ferndale 2	Natural gas combined cycle			Natural Gas	3,435,823,000 scf ⁽³⁾	NR ⁽³⁾	3,709,256 MMBtu	199,983.75 ^{(1), [3]}	3.71 ⁽²⁾	0.37 ⁽²⁾
				Distillate Fuel Oil No. 2	3,140 gal					
Frederickson Unit 1	Natural gas combined cycle	136	49.85%	Natural Gas	4,455,460,399 scf ⁽³⁾	NR ⁽³⁾	9,204,400 MMBtu	247,375.54 ^{(1), [3]}	4.59 ⁽²⁾	1.85 ⁽²⁾
Fredonia 1	Dual-fuel combustion turbines	207	100%	Natural Gas	902,982,000 scf	0.001074 MMBtu/scf	969,803 MMBtu	51,457.73 ⁽³⁾	0.97 ⁽⁵⁾	0.10 ⁽⁵⁾
				Distillate Fuel Oil No. 2	14,267 gal	0.139 MMBtu/gal	1,990 MMBtu	147.17 ⁽³⁾	0.01 ⁽⁵⁾	0.001 ⁽⁵⁾
								<u>51,604.90</u>	<u>0.98</u>	<u>0.10</u>
Fredonia 2	Dual-fuel combustion turbines			Natural Gas	664,423,000 scf	0.001073 MMBtu/scf	712,926 MMBtu	37,827.85 ⁽³⁾	0.71 ⁽⁵⁾	0.07 ⁽⁵⁾
				Distillate Fuel Oil No. 2	25,148 gal	0.139 MMBtu/gal	3,507 MMBtu	259.40 ⁽³⁾	0.01 ⁽⁵⁾	0.002 ⁽⁵⁾
								<u>38,087.25</u>	<u>0.72</u>	<u>0.07</u>
Fredonia 3	Dual-fuel combustion turbines	107	100%	Natural Gas	215,170,500 scf ⁽³⁾	NR ⁽³⁾	233,223 MMBtu	12,610.44 ^{(1), [3]}	0.23 ⁽²⁾	0.02 ⁽²⁾
				Distillate Fuel Oil No. 2	13,609 gal					
Fredonia 4	Dual-fuel combustion turbines			Natural Gas	227,342,400 scf ⁽³⁾	NR ⁽³⁾	246,112 MMBtu	13,303.70 ^{(1), [3]}	0.25 ⁽²⁾	0.02 ⁽²⁾
				Distillate Fuel Oil No. 2	12,609 gal					
Frederickson 1	Dual-fuel combustion turbines	149	100%	Natural Gas	598,967,000 scf	0.001071 MMBtu/scf	641,494 MMBtu	34,037.65 ⁽³⁾	0.64 ⁽⁵⁾	0.06 ⁽⁵⁾
				Distillate Fuel Oil No. 2	727 gal	0.140 MMBtu/gal	102 MMBtu	7.53 ⁽³⁾	0.0003 ⁽⁵⁾	0.0001 ⁽⁵⁾
								<u>34,045.18</u>	<u>0.64</u>	<u>0.06</u>
Frederickson 2	Dual-fuel combustion turbines			Natural Gas	239,322,000 scf	0.001072 MMBtu/scf	256,553 MMBtu	13,612.71 ⁽³⁾	0.26 ⁽⁵⁾	0.03 ⁽⁵⁾
				Distillate Fuel Oil No. 2	964 gal	0.140 MMBtu/gal	135 MMBtu	9.98 ⁽³⁾	0.00 ⁽⁵⁾	0.000 ⁽⁵⁾
								<u>13,622.69</u>	<u>0.26</u>	<u>0.03</u>
Goldendale	Natural gas combined cycle	278	100%	Natural Gas	9,562,471 scf ⁽³⁾	NR ⁽³⁾	10,222,714 MMBtu	551,136.53 ^{(1), [3]}	10.22 ⁽²⁾	1.02 ⁽²⁾
Mint Farm	Natural gas combined cycle	297	100%	Natural Gas	11,839,257,672 scf ⁽³⁾	NR ⁽³⁾	12,707,367 MMBtu	685,082.11 ^{(1), [3]}	12.71 ⁽²⁾	1.27 ⁽²⁾
Sumas	Natural gas cogeneration	127	100%	Natural Gas	4,876,984,400 scf ⁽³⁾	NR ⁽³⁾	5,238,320 MMBtu	282,411.67 ^{(1), [3]}	5.24 ⁽²⁾	0.52 ⁽²⁾
Whitehorn 2	Dual-fuel combustion turbines	149	100%	Natural Gas	437,691,000 scf	0.00107 MMBtu/scf	468,329 MMBtu	24,849.56 ⁽³⁾	0.47 ⁽⁵⁾	0.05 ⁽⁵⁾
				Distillate Fuel Oil No. 2	15,231 gal	0.140 MMBtu/gal	2,134 MMBtu	157.81 ⁽³⁾	0.01 ⁽⁵⁾	0.001 ⁽⁵⁾
								<u>25,007.36</u>	<u>0.47</u>	<u>0.05</u>
Whitehorn 3	Dual-fuel combustion turbines			Natural Gas	220,286,000 scf	0.001071 MMBtu/scf	235,926 MMBtu	12,518.25 ⁽³⁾	0.24 ⁽⁵⁾	0.02 ⁽⁵⁾
				Distillate Fuel Oil No. 2	30,693 gal	0.140 MMBtu/gal	4,300 MMBtu	318.00 ⁽³⁾	0.01 ⁽⁵⁾	0.003 ⁽⁵⁾
								<u>12,836.25</u>	<u>0.25</u>	<u>0.03</u>
Total								2,477,569	46	6

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

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Emission Factors:

Fuel Type	CO ₂ (kg/MMBtu)	CH ₄ (kg/MMBtu)	N ₂ O (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 [5]
Distillate Fuel Oil No. 2	73.96 [4]	3.0E-03 [4]	6.0E-04 [4]	0.138 [5]

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 2015 Form 10-K (Puget Energy 2016).
- [2] PSE 2015 EPA MRR Reporting Form.
- [3] ECMPS Feedback (EPA).
- [4] EPA GHG MRR Subpart C (40 CFR 98.38), Table C-1 & Table C-2.
- [5] AP-42 Ch 3, Table 3.4-1 (EPA October 1996).

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 the WRI/WBCSD GHG Protocol equity share method.

Table A-3. Emission Factors for Firm & Non-Firm Contracts Purchased Electricity**Puget Sound Energy - 2015 Greenhouse Gas Inventory**

Fuel Type	Heat Rate ^[8] (Btu/kWh)	Emission Rate			Emission Rate ^[6]		
		CO ₂ (lb/MMBtu)	CH ₄ (lb/MMBtu)	N ₂ O (lb/MMBtu)	CO ₂ (lb/kWh)	CH ₄ (lb/kWh)	N ₂ O (lb/kWh)
Coal ^[1]	8,800				2.095 [5]	1.241E-05 [7]	2.869E-05 [7]
Anthracite	8,800	228.59 [1]	0.00141 [2]	0.00326 [2]	2.012 [7]	1.241E-05 [7]	2.869E-05 [7]
Bituminous	8,800	205.65 [1]	0.00141 [2]	0.00326 [2]	1.810 [7]	1.241E-05 [7]	2.869E-05 [7]
Sub-Bituminous	8,800	214.22 [1]	0.00141 [2]	0.00326 [2]	1.885 [7]	1.241E-05 [7]	2.869E-05 [7]
Lignite	8,800	215.43 [1]	0.00141 [2]	0.00326 [2]	1.896 [7]	1.241E-05 [7]	2.869E-05 [7]
Natural Gas ^{[2],[5]}					1.321 [5]	3.824E-05 [7]	1.391E-05 [7]
Nat Gas		116.98 [1]	0.000287 [2]	0.000233 [2]			
SCGT	10,783	116.98 [1]	0.000287 [2]	0.000233 [2]	1.261 [7]	3.095E-06 [7]	2.512E-06 [7]
CCGT	6,430	116.98 [1]	0.000287 [2]	0.000233 [2]	0.752 [7]	1.845E-06 [7]	1.498E-06 [7]
Nat Gas Alternative		110 [3]	0.0086 [3]	0.003 [3]			
SCGT	10,783	110 [3]	0.0086 [3]	0.003 [3]	1.186 [7]	9.273E-05 [7]	3.235E-05 [7]
CCGT	6,430	110 [3]	0.0086 [3]	0.003 [3]	0.707 [7]	5.530E-05 [7]	1.929E-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]	10,783	161.27 [1]	0.00163 [2]	0.0014 [2]	1.969 [5]	1.758E-05 [2]	1.510E-05 [2]
Other					0.666 [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 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 1 (DOE/EPA July 2000).
[6] eGRID2012 (EPA October 2015).
[7] Calculated values.
[8] Assumptions to the Annual Energy Outlook 2015, Table 8.2 (DOE/EIA September 2015).

Note(s):

- (1) Assume same heat rate for all coal types. Used 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 - 2015 Greenhouse Gas Inventory

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

Time Horizon	CO ₂	CH ₄	N ₂ O	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 ₂ O	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 ₂ O	SF ₆
100 years	1	21	310	23,900

Global Warming Potentials used in the 2013-2015 GHG inventories ^[4]:

Time Horizon	CO ₂	CH ₄	N ₂ O	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 2001).
 [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 2014).

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

Puget Sound Energy - 2015 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, 2015.
98.3(c)(3)	Date of submittal.	By March 31, 2016.
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 ₂ O, 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 ₂ e calculated using Equation A-1 of this subpart. For electronics manufacturing (as defined in § 98.90), starting in reporting year 2012 the CO ₂ e 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 ₂ O.	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 ₂ O, 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 ₂ e 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 - 2015 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 ₂ e 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 CO ₂ 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 ₂ O. (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 - 2015 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
98.32	You must report CO ₂ , CH ₄ , and N ₂ O 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 ₂ O 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 ₂ e; and	See Table B-7.
98.36(b)(8)(ii)	Metric tons of biogenic CO ₂ e emissions (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 ₂ O 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 ₂ e.	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 ₂ O 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 ₂ e.	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 ₂ e, 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.

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

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
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.
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 ₂ O 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 - 2015 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., V _{total} , in scf. (B) The annual volume of CO ₂ emitted from the combustion of fossil fuels, i.e., V _{ff} , 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., V _{bio} , 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 CO ₂ 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 CO ₂ 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 CO ₂ 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 - 2015 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 ₂ O, 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 ₂ O 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 ₂ O 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 - 2015 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
98.232(a)	You must report CO ₂ , CH ₄ , and N ₂ O emissions from each industry segment specified in paragraph (b) through (i) of this section, CO ₂ , CH ₄ , and N ₂ O 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 ₂ O 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 , CH ₄ , and N ₂ O 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 ₂ O 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 ₂ O 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 ₂ O 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 ₂ O 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 ₂ O 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 ₂ O 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 ₂ O 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 ₂ O 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.

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

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
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.
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(bb)	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 - 2015 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 - 2015 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 ₂ 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 - 2015 Greenhouse Gas Inventory

Unit	Plant Code [2]	Unit ID [1]	Unit Type	PSE Share [1]	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 ₂ e (metric ton)				Emissions (short ton)			Emissions in CO ₂ e (short ton)				
												CO ₂	CH ₄	N ₂ O	CO ₂	CH ₄	N ₂ O	Total	CO ₂	CH ₄	N ₂ O	CO ₂	CH ₄	N ₂ O	Total	
Colstrip Unit 1	6076	1	Coal	50%	1,047	Coal	21,207,487	Yes	NA	4	1/1/2015 - 12/31/2015	1,075,029.98	116.70	16.98	1,075,029.98	2,917.54	5,059.46	1,083,006.98	1,185,017.71	128.64	18.72	1,185,017.71	3,216.03	5,577.10	1,193,810.84	
Colstrip Unit 2		2	Coal	50%		Coal	18,691,705	Yes	NA	4	1/1/2015 - 12/31/2015	992,554.30	102.86	14.96	992,554.30	2,571.48	4,459.37	999,585.15	1,094,103.83	113.38	16.50	1,094,103.83	2,834.57	4,915.62	1,101,854.02	
Colstrip Unit 3		3	Coal	25%	1,262	Coal	57,799,860	Yes	NA	4	1/1/2015 - 12/31/2015	1,449,686.59	158.97	23.12	1,449,686.59	3,974.21	6,890.85	1,460,551.65	1,598,005.92	175.23	25.49	1,598,005.92	4,380.81	7,595.87	1,609,982.60	
Colstrip Unit 4		4	Coal	25%		Coal	60,482,456	Yes	NA	4	1/1/2015 - 12/31/2015	1,480,031.41	166.34	24.20	1,480,031.41	4,158.58	7,210.50	1,491,400.50	1,631,455.37	183.36	26.67	1,631,455.37	4,584.05	7,948.22	1,643,987.64	
Encogen 1	7870	CT1	Natural gas cogeneration	100%	563	Natural Gas	671,028	Yes	Yes	4	1/1/2015 - 12/31/2015	36,196.30	0.67	0.07	36,196.30	16.78	20.00	36,233.07	39,899.59	0.74	0.07	39,899.59	18.49	22.04	39,940.13	
Encogen 2		CT2	Natural gas cogeneration			Natural Gas	1,013,869	Yes	Yes	4	1/1/2015 - 12/31/2015	54,672.20	1.01	0.10	54,672.20	25.35	30.21	54,727.76	60,265.79	1.12	0.11	60,265.79	27.94	33.30	60,327.03	
Encogen 3		CT3	Natural gas cogeneration			Natural Gas	966,388	Yes	Yes	4	1/1/2015 - 12/31/2015	52,102.89	0.97	0.10	52,102.89	24.16	28.80	52,155.84	57,433.60	1.07	0.11	57,433.60	26.63	31.74	57,491.98	
Ferndale 1	54537	CT-1A	Natural gas combined cycle	100%	863	Natural Gas	3,808,333	Yes	NA	4	1/1/2015 - 12/31/2015	205,325.50	3.81	0.38	205,325.50	95.21	113.49	205,534.19	226,332.62	4.20	0.42	226,332.62	104.95	125.10	226,562.67	
Ferndale 2		CT-1B	Natural gas combined cycle	0%		Natural Gas	3,709,256	Yes	NA	4	1/1/2015 - 12/31/2015	199,983.75	3.71	0.37	199,983.75	92.73	110.54	200,187.02	220,444.35	4.09	0.41	220,444.35	102.22	121.84	220,668.41	
Frederickson Unit 1	55818	F1CT	Natural gas combined cycle	49.85%	464	Natural Gas	9,204,400	Yes	Yes	4	1/1/2015 - 12/31/2015	247,375.54	4.59	1.85	247,375.54	114.71	550.23	248,040.48	272,684.85	5.06	2.04	272,684.85	126.45	606.53	273,417.83	
Fredonia 1	607	CT1	Dual-fuel combustion turbines	100%	706	Natural Gas	969,803	No	NA	2	1/1/2015 - 12/31/2015	51,457.73	0.97	0.10	51,457.73	24.25	28.90	51,510.87	56,722.44	1.07	0.11	56,722.44	26.73	31.86	56,781.02	
						Distillate Fuel Oil No. 2	1,990	No	NA	2	1/1/2015 - 12/31/2015	147.17	0.01	0.00	147.17	0.15	0.36	147.67	162.22	0.01	0.00	162.22	0.16	0.39	162.78	
Fredonia 2		CT2	Dual-fuel combustion turbines				Natural Gas	712,926	No	NA	2	1/1/2015 - 12/31/2015	37,827.85	0.71	0.07	37,827.85	17.82	21.25	37,866.92	41,698.06	0.79	0.08	41,698.06	19.65	23.42	41,741.13
							Distillate Fuel Oil No. 2	3,507	No	NA	2	1/1/2015 - 12/31/2015	259.40	0.01	0.00	259.40	0.26	0.63	260.29	285.94	0.01	0.00	285.94	0.29	0.69	286.93
Fredonia 3		CT3	Dual-fuel combustion turbines	100%	365	Natural Gas	233,223	Yes	NA	4	1/1/2015 - 12/31/2015	12,610.44	0.23	0.02	12,610.44	5.83	6.95	12,623.22	13,900.63	0.26	0.03	13,900.63	6.43	7.66	13,914.72	
Fredonia 4		CT4	Dual-fuel combustion turbines			Natural Gas	246,112	Yes	NA	4	1/1/2015 - 12/31/2015	13,303.70	0.25	0.02	13,303.70	6.15	7.33	13,317.19	14,664.82	0.27	0.03	14,664.82	6.78	8.08	14,679.69	
Frederickson 1	99	CT1	Dual-fuel combustion turbines	100%	508	Natural Gas	641,494	No	Yes	2	1/1/2015 - 12/31/2015	34,037.65	0.64	0.06	34,037.65	16.04	19.12	34,072.81	37,520.09	0.71	0.07	37,520.09	17.68	21.07	37,558.84	
						Distillate Fuel Oil No. 2	102	No	Yes	2	1/1/2015 - 12/31/2015	7.53	0.00	0.00	7.53	0.01	0.02	7.55	8.30	0.00	0.00	8.30	0.01	0.02	8.32	
Frederickson 2		CT2	Dual-fuel combustion turbines				Natural Gas	256,553	No	Yes	2	1/1/2015 - 12/31/2015	13,612.71	0.26	0.03	13,612.71	6.41	7.65	13,626.77	15,005.45	0.28	0.03	15,005.45	7.07	8.43	15,020.94
						Distillate Fuel Oil No. 2	135	No	Yes	2	1/1/2015 - 12/31/2015	9.98	0.00	0.00	9.98	0.01	0.02	10.01	11.00	0.00	0.00	11.00	0.01	0.03	11.04	
Goldendale	55482	CT-1	Natural gas combined cycle	100%	949	Natural Gas	10,222,714	Yes	Yes	4	1/1/2015 - 12/31/2015	551,136.53	10.22	1.02	551,136.53	255.57	304.64	551,696.73	607,524.03	11.27	1.13	607,524.03	281.72	335.80	608,141.55	
Mint Farm	55700	CTG1	Natural gas combined cycle	100%	1,013	Natural Gas	12,707,367	Yes	Yes	4	1/1/2015 - 12/31/2015	685,082.11	12.71	1.27	685,082.11	317.68	378.68	685,778.47	755,173.75	14.01	1.40	755,173.75	350.19	417.42	755,941.36	
Sumas	54476	CT-1	Natural gas cogeneration	100%	433	Natural Gas	5,238,320	Yes	Yes	4	1/1/2015 - 12/31/2015	282,411.67	5.24	0.52	282,411.67	130.96	156.10	282,698.73	311,305.57	5.77	0.58	311,305.57	144.36	172.07	311,622.00	
Whitehorn 2	6120	CT2	Dual-fuel combustion turbines	100%	508	Natural Gas	468,329	No	NA	2	1/1/2015 - 12/31/2015	24,849.56	0.47	0.05	24,849.56	11.71	13.96	24,875.22	27,391.95	0.52	0.05	27,391.95	12.91	15.38	27,420.24	
						Distillate Fuel Oil No. 2	2,134	No	NA	2	1/1/2015 - 12/31/2015	157.81	0.01	0.00	157.81	0.16	0.38	158.35	173.95	0.01	0.00	173.95	0.18	0.42	174.55	
Whitehorn 3		CT3	Dual-fuel combustion turbines				Natural Gas	235,926	No	NA	2	1/1/2015 - 12/31/2015	12,518.25	0.24	0.02	12,518.25	5.90	7.03	12,531.18	13,799.01	0.26	0.03	13,799.01	6.50	7.75	13,813.26
						Distillate Fuel Oil No. 2	4,300	No	NA	2	1/1/2015 - 12/31/2015	318.00	0.01	0.00	318.00	0.32	0.77	319.09	350.54	0.01	0.00	350.54	0.36	0.85	351.74	
Total												7,512,706.52	591.60	85.33	7,512,706.52	14,789.97	25,427.22	7,552,923.71	8,281,341.37	652.13	94.06	8,281,341.37	16,303.15	28,028.72	8,325,673.24	

Calculation Inputs:

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

Data Source:

- [1] ECMP Feedback (EPA).
[2] PSE.
[3] Puget Energy 2015 Form 10-K (Puget Energy 2016).

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 - 2015 Greenhouse Gas Inventory

Component	Emission Factor ^[7]	(UOM)	Count ^{[1],[2],[1]}	Duration Component Leaking (hr) ^[2]	Emissions (metric ton)		Emissions in CO ₂ e (metric ton) ^[3]
					CO ₂	CH ₄	CO ₂ e
Below Grade M&R Station							
Below Grade M&R Station Components > 300 psig	1.30	scf/hr/station	3	8,760	0.02 {2}	1 {2}	16
Below Grade M&R Station Components 100 to 300 psig	0.20	scf/hr/station	325	8,760	0.33 {2}	10.7 {2}	267
Below Grade M&R Station Components < 100 psig	0.10	scf/hr/station	10	8,760	0.01 {2}	0.2 {2}	4
Below Grade M&R Station Total					0.4	11.5	
Distribution Mains							
Unprotected Steel	12.58	scf/hr/mile	0	8,760	0.00 {2}	0 {2}	0
Protected Steel	0.35	scf/hr/mile	4,119	8,760	7.31 {2}	236.4 {2}	5,918
Plastic	1.13	scf/hr/mile	8,477	8,760	48.55 {2}	1,571 {2}	39,319
Cast Iron	27.25	scf/hr/mile	0	8,760	0 {2}	0 {2}	0
Distribution Mains Total					55.9	1,807.2	45,237.0
Distribution Services							
Unprotected Steel	0.19	scf/hr/#services	0	8,760	0.00 {2}	0 {2}	0
Protected Steel	0.02	scf/hr/#services	126,244	8,760	12.80 {2}	414 {2}	10,364
Plastic	0.001	scf/hr/#services	663,028	8,760	3.36 {2}	109 {2}	2,722
Copper	0.03	scf/hr/#services	0	8,760	0 {2}	0 {2}	0
Distribution Services Total					16.2	522.8	13,086
Total					72	2,341	58,323

Other Reporting Data:

98.236(r)(2)(i)	Number of above grade T-D transfer stations at the facility	34	[1]
98.236(r)(2)(ii)	Number of above grade metering-regulating stations that are not T-D transfer stations at the facility	113	[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	113	[1]
98.236(r)(2)(iv)	Average estimated time that each meter/regulator run at above grade M&R stations that are not above grade T-D transfer stations	8,760	[1]
98.236(r)(2)(v)(A)	Annual CO ₂ emissions from above grade M&R stations that are not above grade T-D transfer stations	0	[1]
98.236(r)(2)(v)(B)	Annual CH ₄ emissions from above grade metering-regulating stations that are not above grade T-D transfer stations	0	[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.	103,294,400	Msc [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.	14,073,053	Msc [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.	16,678,792	Msc [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.	22,091,488	Msc [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.	1,611,282	Msc [8]
93.236(aa)(9)(vi)	The quantity of natural gas consumed by the LDC for operational purposes, in thousand standard cubic feet.	0	Msc [8]
93.236(aa)(9)(vii)	The estimated quantity of gas stolen in the calendar year, in thousand standard cubic feet	0	Msc [8]

Calculation Inputs:

GHG	GHG Concentration ^{[4],[5]}	Density (kg/ft ³) ^[6]
CO ₂	1.1E-02	0.0526
CH ₄	0.975	0.0192
N ₂ O	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 2015 (PSE 2016).
- [2] PSE 2015 M&R Survey (PSE 2016).
- [3] Puget Energy 2015 Form 10-K (PSE 2016).
- [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 (2016)

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 - 2015 Greenhouse Gas Inventory

SF₆ Inventory (not energized)			
98.306(d)	SF ₆ at the beginning of the year	7,475	lb
98.306(e)	SF ₆ at the end of the year	5,512	lb
	Decrease in SF₆ inventory	1,963	lb (2)
Acquisitions of SF₆			
98.306(f)	SF ₆ purchased from chemical producers or distributors in bulk	1,035	lb
98.306(g)	SF ₆ purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear	48	lb
98.306(h)	SF ₆ returned to facility after off-site recycling	0	lb
	Acquisitions of SF₆	1,083	lb (2)
Disbursements of SF₆			
98.306(i)	SF ₆ in bulk and contained in equipment that is sold to other entities	0	lb
98.306(j)	SF ₆ returned to suppliers	0	lb
98.306(k)	SF ₆ sent off site for recycling	0	lb
98.306(l)	SF ₆ sent off site for destruction	0	lb
	Disbursements of SF₆	0	lb (2)
Nameplate Capacity of Equipment Operated			
98.306(a)	Nameplate capacity of new equipment in pounds, including hermetically sealed-pressure switchgear	2,810	lb
98.306(a)(2)	Nameplate capacity of retiring equipment in pounds, including hermetically sealed-pressure switchgear	2,536	lb
98.306(a)(3)	Net Increase in Total Nameplate Capacity of Equipment Operated	274	lb (2)
User Emissions			
		2,772	lb
		1.257	metric ton
		30,049	metric ton CO₂e
Other Reporting Data:			
98.306(a)(1)	Existing at the beginning of the year (excluding hermetically sealed-pressure switchgear)	43,304	lb [1]
98.306(a)(2)	New during the year (all SF ₆ -insulated equipment, including hermetically sealed-pressure switchgear)	2,810	lb [1]
98.306(a)(3)	Retired during the year (all SF ₆ -insulated equipment, including hermetically sealed-pressure switchgear)		[1]
		2,536	lb
98.306(b)	Transmission miles (length of lines carrying voltages above 35 kilovolt)	2,609	lb [1]
98.306(c)	Distribution miles (length of lines carrying voltages at or below 35 kilovolt)	20,499	lb [1]
98.306(d)	Pounds of SF ₆ and PFC stored in containers, but not in energized equipment, at the beginning of the year		[1]
		7,475	lb
98.306(e)	Pounds of SF ₆ and PFC stored in containers, but not in energized equipment, at the end of the year	5,512	lb [1]
98.306(f)	Pounds of SF ₆ and PFC purchased in bulk from chemical producers or distributors	1,035	lb [1]
98.306(g)	Pounds of SF ₆ and PFC purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear		[1]
		48	lb
98.306(h)	Pounds of SF ₆ and PFC returned to facility after off-site recycling	0	lb [1]
98.306(i)	Pounds of SF ₆ and PFC in bulk and contained in equipment sold to other entities	0	lb [1]
98.306(j)	Pounds of SF ₆ and PFC returned to suppliers	0	lb [1]
98.306(k)	Pounds of SF ₆ and PFC sent off-site for recycling	0	lb [1]
98.306(l)	Pounds of SF ₆ and PFC sent off-site for destruction	0	lb [1]

Calculation Methodology:

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

Data Source:

[1] Subpart NN Reporting Form 2015 (PSE 2016).

Note(s):

(1) See Table A-4 for Global Warming Potentials.

Table B-10. EPA GHG MRR Subpart NN Calculations

Puget Sound Energy - 2015 Greenhouse Gas Inventory

98.403(a)	Natural Gas Received at City Gate			
	Fuel	103,294,400	Mscf	[1]
	EF	0.0544	metric ton CO ₂ / Mscf	[2]
	CO_{2i}	5,619,215	metric ton	{1}, (1)
98.403(b)(1)	Natural Gas Received for Redelivery to Downstream Gas Transmission Pipelines and Other LDC			
	Fuel	22,091,488	Mscf	[3]
	EF	0.0544	metric ton CO ₂ / Mscf	[2]
	CO_{2j}	1,201,777	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	14,776,480	3900 Jefferson Road	5000813589
	Total	14,776,480		
	Fuel	1,477,648	Mscf	[4]
	EF	0.0544	metric ton CO ₂ / Mscf	[2]
	CO_{2k}	80,384	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			
	Fuel	16,678,792	Mscf	[5]
	Natural Gas Removed from Storage or Vaporized and Removed from Storage and Used for Deliveries to Customers or Other LDCs			
	Fuel	14,073,053	Mscf	[6]
	EF	0.0544	metric ton CO ₂ / Mscf	[2]
	CO_{2l}	141,752	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	1,611,282	Mscf	[7]
	EF	0.0544	metric ton CO ₂ / Mscf	[2]
	CO_{2n}	87,654	metric ton	{5}
98.403(b)(4)	Total CO₂ Emissions			
	CO₂	4,282,956	metric ton	{6}

Table B-10. EPA GHG MRR Subpart NN Calculations

Puget Sound Energy - 2015 Greenhouse Gas Inventory

Other Reporting Data:

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.								
						103,294,400	Mscf		
98.406(b)(2)	Annual volume in Mscf of natural gas placed into storage or liquefied and stored (Fuel ₁ in Equation NN-5a).					16,678,792	Mscf		
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 (Fuel ₂ in Equation NN-5a).					14,073,053	Mscf		
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 ₁ in Equation NN-5b).					1,611,282	Mscf		
98.406(b)(6)	Annual volume in Mscf of natural gas delivered to downstream gas transmission pipelines and other local distribution companies.					22,091,488	Mscf		
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.					1,477,648	Mscf		
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).								
						CO _{2i} =	5,619,215	metric ton	
						CO _{2j} =	1,201,777	metric ton	
						CO _{2k} =	80,384	metric ton	
						CO _{2l} =	141,752	metric ton	
						CO _{2n} =	87,654	metric ton	
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).					4,282,956	metric ton		
98.406(b)(13)(i)	Residential consumers.	Owned by PSE:	49,299,668	Mscf	[8]	Not owned by PSE:	0	Mscf	[8]
		Total:	49,299,668	Mscf					
98.406(b)(13)(ii)	Commercial consumers.	Owned by PSE:	27,316,532	Mscf	[9]	Not owned by PSE:	5,048,343	Mscf	[9]
		Total:	32,364,875	Mscf					
98.406(b)(13)(iii)	Industrial consumers.	Owned by PSE:	2,505,006	Mscf	[10]	Not owned by PSE:	16,990,849	Mscf	[10]
		Total:	19,495,855	Mscf					
98.406(b)(13)(iv)	Electricity generating facilities.	Owned by PSE:	0	Mscf	[11]	Not owned by PSE:	0	Mscf	[11]
		Total:	0	Mscf					

Calculation Methodology:

- {1} EPA GHG MRR Subpart NN (40 CFR 98.403(2)) (Eq. NN-2).
- {2} EPA GHG MRR Subpart NN (40 CFR 98.403(2)) (Eq. NN-3).
- {3} EPA GHG MRR Subpart NN (40 CFR 98.403(2)) (Eq. NN-4).
- {4} EPA GHG MRR Subpart NN (40 CFR 98.403(2)) (Eq. NN-5a).
- {5} EPA GHG MRR Subpart NN (40 CFR 98.403(2)) (Eq. NN-5b).
- {6} EPA GHG MRR Subpart NN (40 CFR 98.403(2)) (Eq. NN-6).

Data Source:

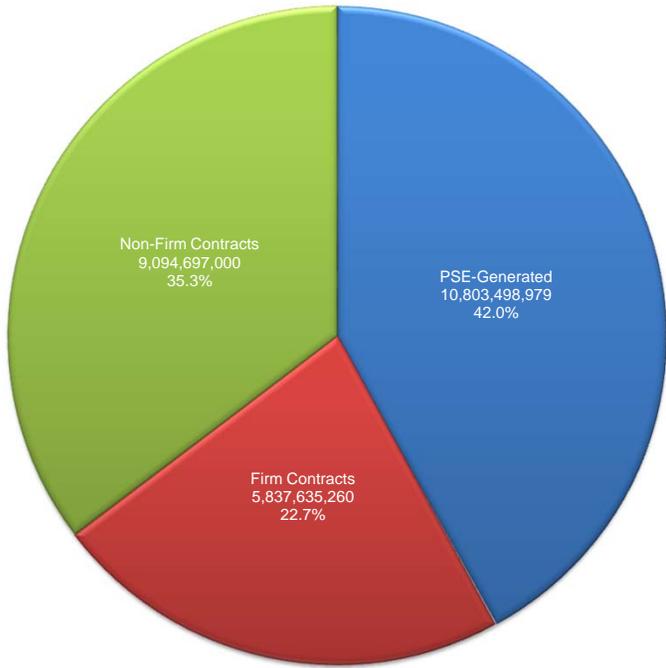
- [1] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2016), Box 4.1 + 4.2.
- [2] EPA GHG MRR Subpart NN (40 CFR 98.408), Table NN-2.
- [3] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2016), Box 4.2.
- [4] 2015 PSE Therm Reporting (PSE 2016).
- [5] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2016), Box 13.1.
- [6] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2016), Box 2.1.
- [7] PSE.
- [8] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2016), Box 10.1, 11.1.
- [9] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2016), Box 10.2, 11.2.
- [10] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2016), Box 10.3, 11.3.
- [11] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2016), Box 10.4, 11.4.

Note(s):

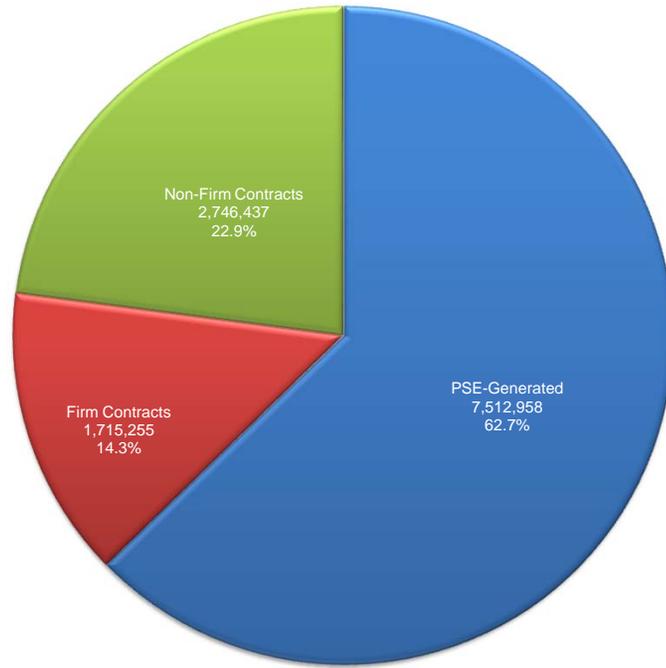
- (1) Reporters to EPA must use one of two methods to calculate the CO₂ emissions that would result from the complete combustion and oxidation of natural gas supply. The first method (Equation NN-1) uses either a measured or default fuel heating value, and either a measured or default CO₂ emissions factor, and is most appropriate for liquid fuels. The second method (Equations NN-2) uses either a measured or default CO₂ emissions factor and is most appropriate for gaseous fuels. PSE uses the second method and default emission factor option.

Figure 7-1. Total Electricity and its CO2 Emissions

Puget Sound Energy - 2015 Greenhouse Gas Inventory



Electricity (kWh)



CO₂ Emissions (metric ton)

Figure 7-2. Total Electricity by Generation Source and its CO2 Emissions

Puget Sound Energy - 2015 Greenhouse Gas Inventory

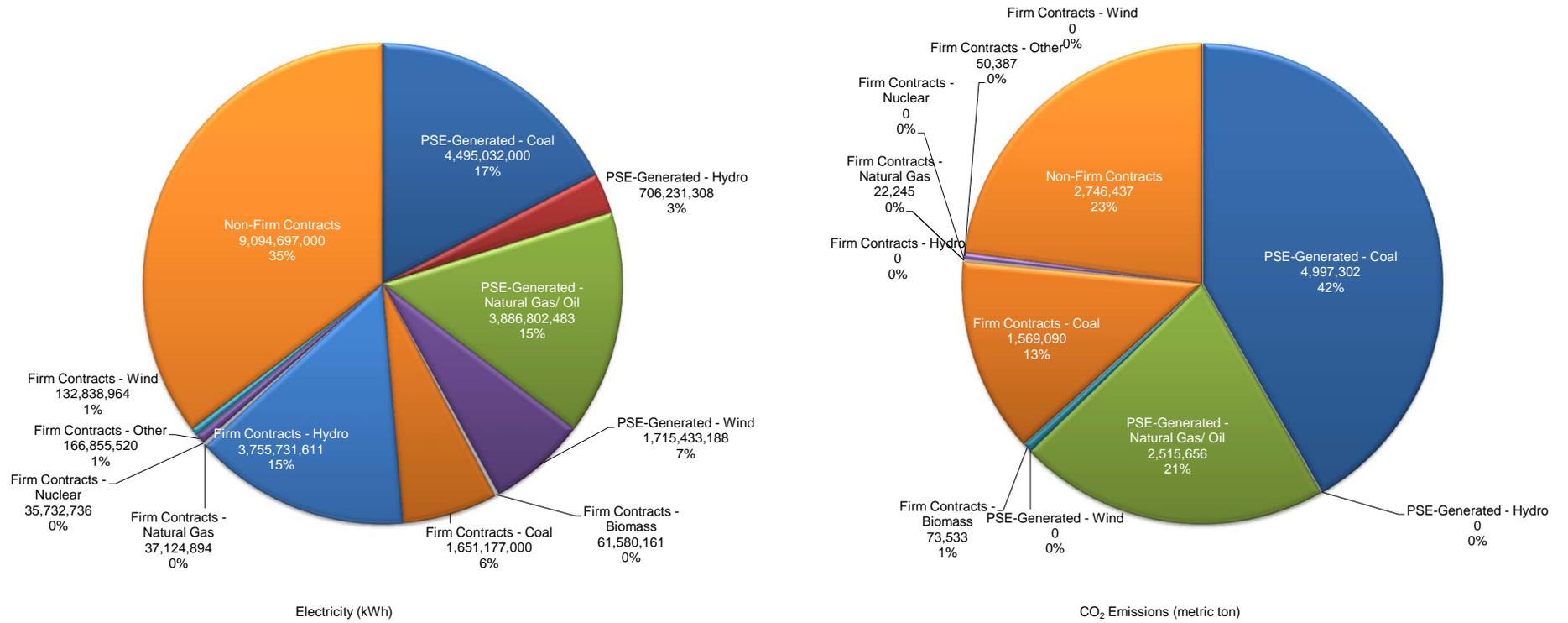


Figure 7-3. PSE-Generated Electricity by Generation Source and its CO2 Emissions

Puget Sound Energy - 2015 Greenhouse Gas Inventory

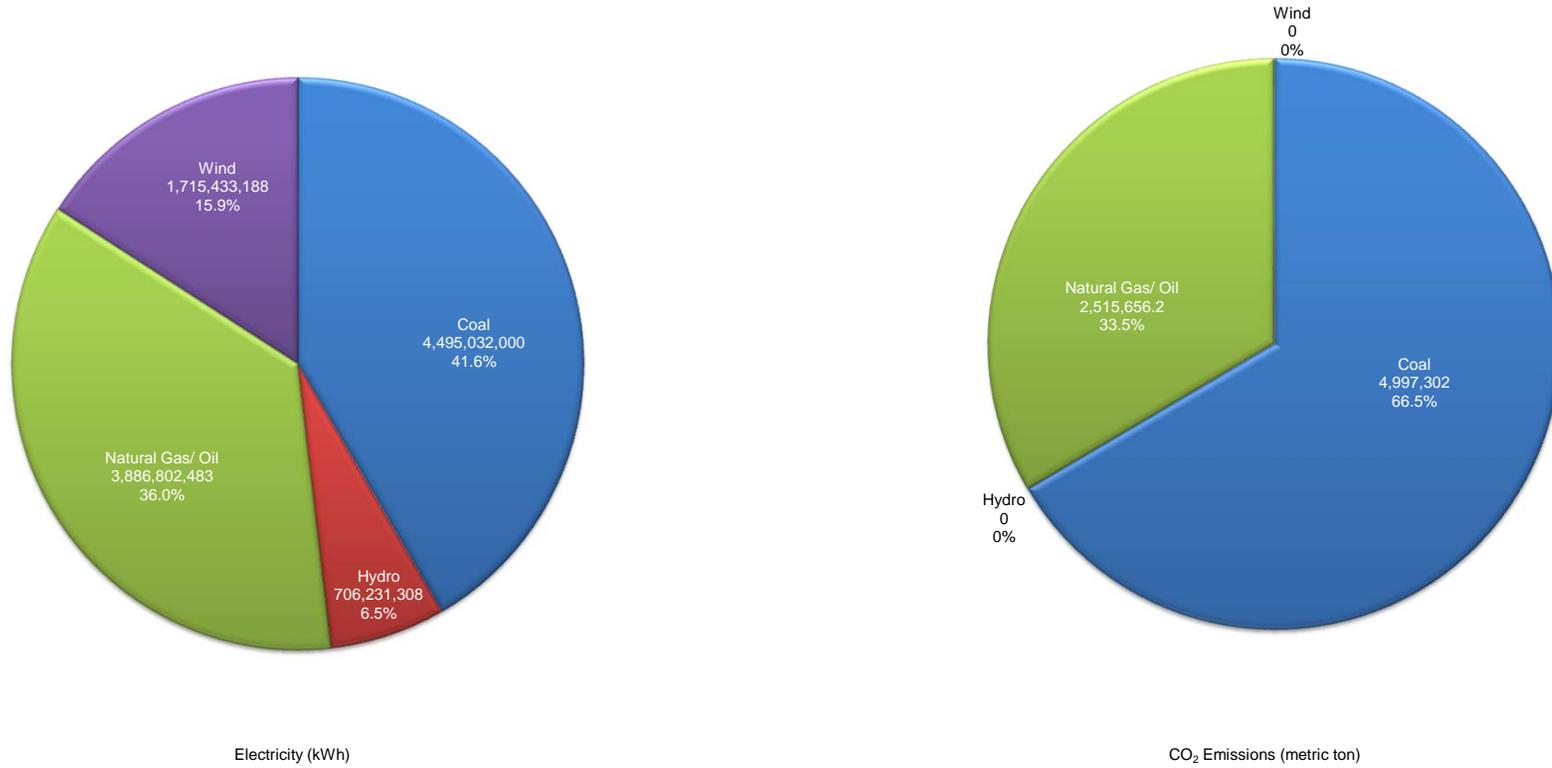


Figure 7-4. Firm Contract Purchased Electricity and its CO2 Emissions

Puget Sound Energy - 2015 Greenhouse Gas Inventory

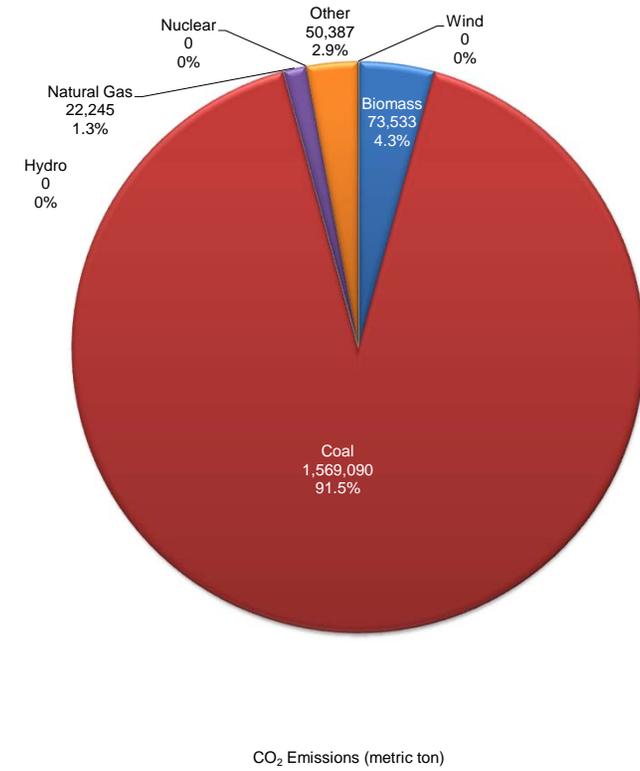
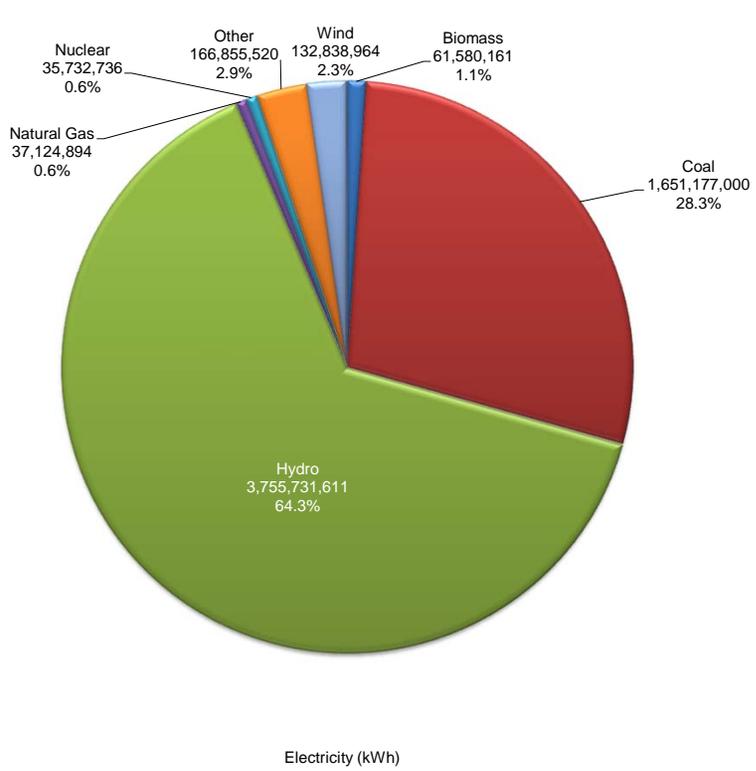
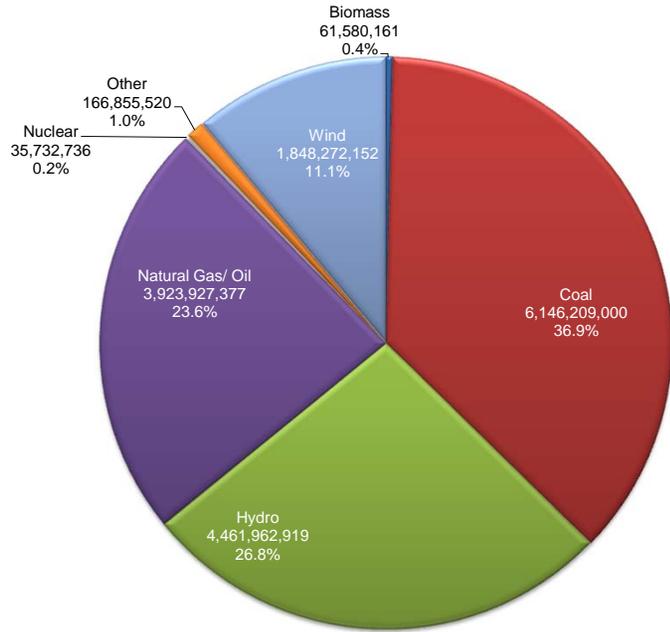
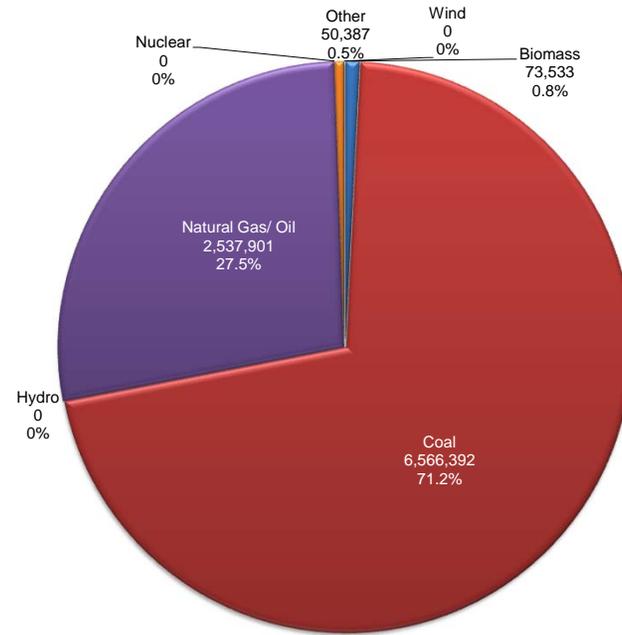


Figure 7-5. PSE-Generated and Firm Contract Purchased Electricity by Generation Source and its CO2 Emissions

Puget Sound Energy - 2015 Greenhouse Gas Inventory



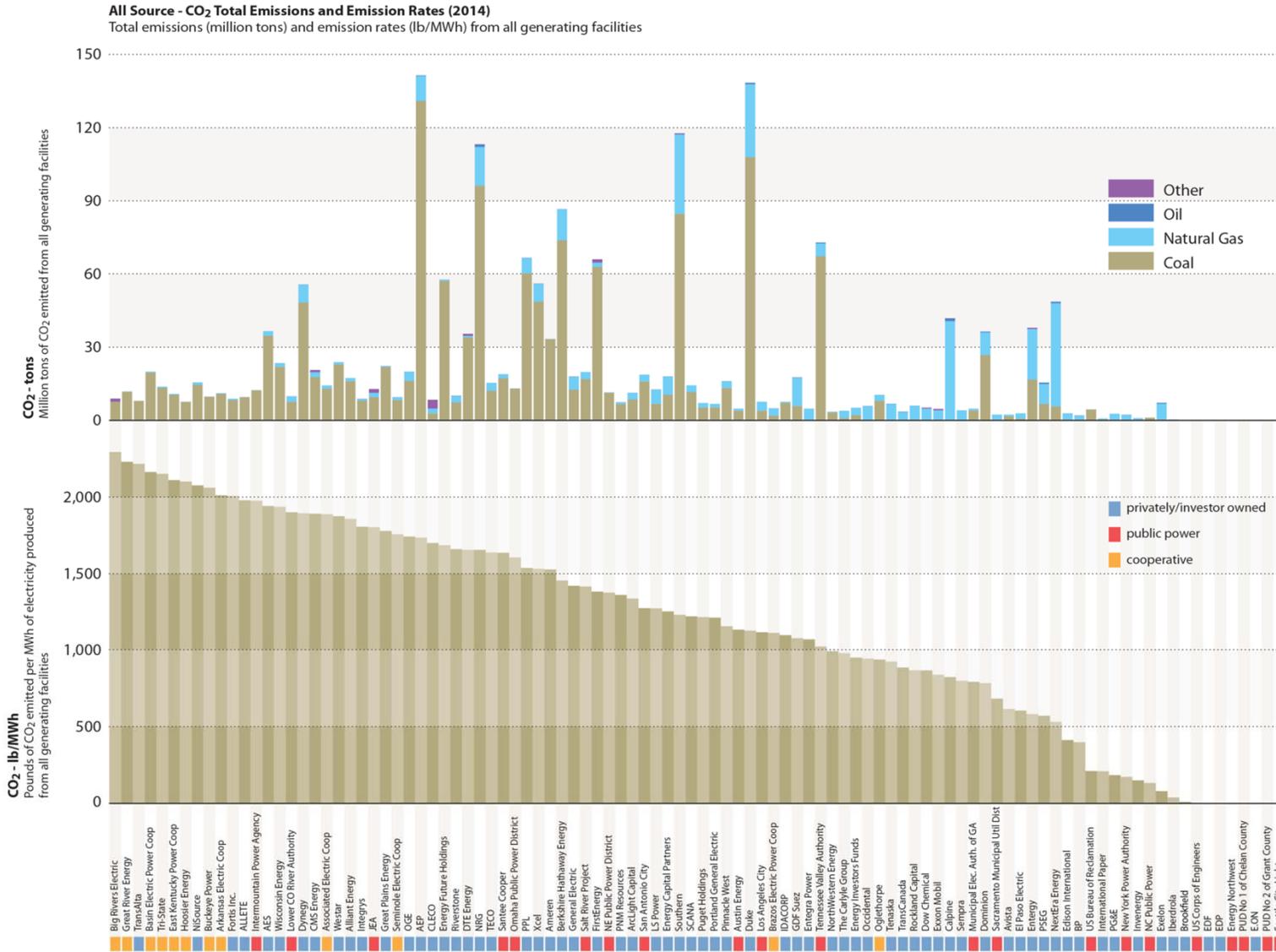
Electricity (kWh)



CO₂ Emissions (metric ton)

Figure 9-1. Comparison of PSE’s Total CO2 Emissions and Emission Rates to Other Electric Utilities

Puget Sound Energy - 2015 Greenhouse Gas Inventory



Data Source:
 (1) CERES/ NRDC/ PSEG/ PG&E Corporation, Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States, Figure 13 (July 2016).