Environment

Submitted to:
Puget Sound Energy
Bellevue, WA

Submitted by:
AECOM
Seattle, WA
60285724
July 2013

Puget Sound Energy 2012 Greenhouse Gas Inventory

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2012 Greenhouse Gas Inventory
Final

Submitted Electronically

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Executive Summary

Puget Sound Energy's (PSE) operating rates and greenhouse gas (GHG) emissions for calendar year 2012 are summarized below in Table ES-1, Table ES-2, and Table ES-3. Emission percentages indicated in Table ES-2 are the percentage of the total emissions of the particular pollutant within each scope. 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 2012 Operating Rates

	Electric Operations	**Natural Gas Operations**
Throughput	24,758,012,912 kWh	903,534,000 therm
Customers Served (Average)	1,089,296	763,655
Revenue (000)	$2,128,230	$1,086,095

Table ES-2. Calendar Year 2012 Greenhouse Gas Emissions by Scope

	CO_2		**CH_4**		**N_2O**		**SF_6**	
	metric ton	**%**	**metric ton**	**%**	**metric ton**	**%**	**metric ton**	**%**
PSE-owned Electric Operations	5,435,979	100%	430	15%	62	100%	-0.005	100%
PSE-owned Natural Gas Operations	76	0%	2469	85%	0	0%	0	NC
Total Scope I	**5,436,055**	**100%**	**2,899**	**100%**	**62**	**100%**	**-0.005**	**100%**
Electricity Purchases	4,455,991	48%	67	100%	103	100%	0	NC
Natural Gas Supply to End-Users	4,813,167	52%	0	0%	0	0%	0	NC
Total Scope III	**9,269,159**	**100%**	**67**	**100%**	**103**	**100%**	**0**	**NC**
Total Outside Scope	**25,246**	**100%**	**0**	**NC**	**0**	**NC**	**0**	**NC**

Notes: CO_2 = carbon dioxide, CH_4 = methane, N_2O = nitrous oxide, SF_6 = sulfur hexafluoride, NC = not calculated.

Table ES-3. Calendar Year 2012 Greenhouse Gas Emissions by Source

	CO_2		CH_4		N_2O		SF_6	
	metric ton	**%**	**metric ton**	**%**	**metric ton**	**%**	**metric ton**	**%**
Generated and Purchased Electricity	9,917,217	67.3%	497	16.8%	165	100%	-0.005	100%
Natural Gas Operations	76	0%	2,469	83.2%	0	0%	0	0%
Natural Gas Supply to End-Users	4,813,167	32.7%	0	0%	0	0%	0	0%
Emissions from All Sources	**14,730,460**	**100%**	**2,965**	**100%**	**165**	**100%**	**-0.005**	**100%**

Notes: CO_2 = carbon dioxide, CH_4 = methane, N_2O = nitrous oxide, SF_6 = sulfur hexafluoride.

A majority of the carbon dioxide (CO_2) emissions were from generated and purchased electricity (67.3%), while the remaining emissions were from natural gas supply to end-users (32.7%). For methane (CH_4), the majority of emissions were from fugitive emissions from natural gas operations (83.2%). Generated and purchased electricity also accounted for all nitrous oxide (N_2O) emissions. The sulfur hexafluoride (SF_6) emissions were insignificant.

Of the electricity PSE delivered in 2012, 32.9% was generated by PSE and 67.1% was purchased (26.3% via firm contracts and 40.8% via non-firm contracts). Of the GHG emissions associated with electricity, about 54.8% were from electricity generated by PSE and about 45.2% were from purchased electricity (7.3% via firm contracts and 37.9% 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 CO_2 per kilowatt hour [kWh]). For example, about 46.8% of the electricity generated by PSE came from coal combustion, but this electricity source represented about 75.6% of the CO_2 emissions from electricity generated by PSE. Hydroelectric plants in the Pacific Northwest accounted for about 71.7% of the firm contract purchased electricity and produced essentially zero GHG emissions.

Compared to 2011, the total electricity throughput decreased by 7% and GHG emissions decreased by 4%. The combination of a decrease in electricity generated by PSE from coal-combustion (higher GHG emission intensity), and an increase in natural gas/oil (lower GHG emission intensity), hydro and wind (zero GHG emission intensity), resulted in a decrease in the overall emission intensity for electricity generated by PSE compared to 2011. The combination of a decrease in firm contract purchased electricity (lower GHG emission intensities), decrease in PURPA purchased electricity (higher GHG emission intensities), and increase in non-firm contract and biomass generated firm contract purchased electricity (higher GHG emission intensities), resulted in an overall emission intensity for electricity purchased by PSE being the same compared to 2011.

PSE continues to be moderate in terms of GHG emissions intensity as compared to other utilities. Electric generation owned by PSE has a higher CO_2 emissions intensity than the national average, but it is moderate in comparison to other large electricity generators. PSE's overall CO_2 emissions 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. Emissions associated with the "direct use" of natural gas by end-users together with emissions associated with power generation and power deliveries from natural gas combustion (direct and indirect) are accounted for in this inventory.

1. Introduction

This document presents an inventory of greenhouse gas (GHG) emissions from Puget Sound Energy (PSE) operations during the calendar year 2012. PSE's primary business is electric generation, purchase, distribution, and sales and natural gas purchase, distribution, and sales. This inventory accounts for the four major GHGs most relevant to PSE's businesses. They are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6). GHG emissions were calculated in accordance with a standardized nationally accepted protocol.

1.1 Purpose

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

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

1.2 Inventory Organization

This inventory is organized into eleven 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 consists of a series of tables used to present and analyze PSE's GHG emissions during calendar year 2012. 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. 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: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs). Two of the groups of gases, HFCs, and PFCs, are not tracked quantitatively in this inventory because PSE's emissions of these GHGs are negligible.

2.1 Recent Regulatory Actions

This inventory continues to incorporate many of the standards developed by the WRI/WBSCD. However, recent regulatory actions at the federal and state levels require PSE to disclose its emissions using newly-set procedures. To stay abreast of these actions, PSE has started integrating these new standards into this report.

On September 22, 2009, the U.S. Environmental Protection Agency (EPA) signed the *Greenhouse Gas Mandatory Reporting Rule* (GHG MRR) (EPA 2009). The rule requires reporting of GHG emissions 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 greenhouse gases, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more of carbon dioxide equivalent ($CO2_e$) per calendar year are required to submit annual reports to 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 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 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 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, 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 starts with 2012 emissions, which are to be reported in 2013.

2.2 Inventory and GHG Reporting Compliance

This inventory is intended to meet the compliance requirements set forth in the federal and state GHG reporting requirements. After the promulgation of the GHG MRR on October 30, 2009, PSE started incorporating GHG MRR calculation methodologies in the 2009 GHG inventory, with the objective of preparing to meet compliance requirements starting in the 2010 reporting year. The GHG MRR, however, has evolved since its first promulgation in 2009. Therefore, new calculation methodologies continue to be added to the GHG inventory to achieve alignment with the new GHG MRR requirements.

Since 2011, CO_2, CH_4, N_2O, and SF_6 emissions are quantified using methodologies established in Subparts A, C, D, W, DD, and NN.

Facilities report GHG emissions based on the EPA's GHG reporting program. The GHG emissions required to be reported to Ecology use the same calculation methodology as the EPA's GHG MRR. The difference in reporting requirement is that Washington State has a lower reporting threshold of 10,000 metric tons of carbon dioxide equivalent ($CO2_e$) per calendar year. As such, PSE's GHG inventory continues to enable PSE to comply with local, state, and federal reporting requirements; to manage its GHG emissions; and to better adapt to future emission reduction programs as they are adopted.

3. Major Accounting Issues

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

- **Relevance.** Ensure the GHG inventory appropriately reflects the GHG emissions of the company and serves the decision-making needs of users—both internal and external. *The intended uses of this inventory are discussed in Section 1.1.*
- **Completeness.** Account for and report on all GHG emission sources and activities within the chosen inventory boundary. Disclose and justify any specific exclusions. *The organizational and operational boundaries chosen by PSE are discussed in Section 4.0. Emission sources that are not included in this inventory are presented in Section 7.2.1.*
- **Consistency.** Use consistent methodologies to allow for meaningful comparisons of emissions over time. Transparently document any changes to the data, inventory boundary, methods, or any other relevant factors in the time series. *PSE has compiled an annual GHG inventory since 2002. PSE has remained, to the best of its ability, consistent in its emission calculation methodology to allow for meaningful comparisons of emissions over time. However, small changes in the emission calculation methodology have been made over the years due to the changes in data availability. The intention of making these small changes is to increase overall accuracy of the inventory. The differences in data sources and methodologies are presented in Section 8.3.*
- **Transparency.** Address all relevant issues in a factual and coherent manner, based on a clear audit trail. Disclose any relevant assumptions and make appropriate references to the accounting and calculation methodologies and data sources used. *Calculation methodologies, sources of data, and assumptions are documented by emission scope in Section 5.0. The references used are listed in Section 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. 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) *2012 Annual Report (Form 10-K)* (Puget Energy 2012). The information presented in this document was extracted from the *2012 Annual Report* and supplemented by additional information provided by relevant PSE personnel.

4.1.1 Electric Operations

In 2012, PSE supplied electricity to 1,089,296 customers in Western Washington. PSE wholly owns three dual-fuel combustion turbine generation facilities (Fredonia, Frederickson, and Whitehorn), three natural gas combined cycle generation facilities (Encogen, Goldendale and Mint Farm), two natural gas cogeneration facilities (Ferndale, and Sumas), one internal diesel combustion generation facility (Crystal Mountain), three hydroelectric generation facilities (Electron, Lower Baker, and Upper Baker), and three wind power generation facilities (Lower Snake River, Wild Horse and Hopkins Ridge). Also, PSE partially owns one coal-combustion generation facility (Colstrip) and one natural gas combined cycle generation facility (Frederickson 1). All of the generation facilities are located in Western Washington, except the coal-combustion generation facility (Colstrip), three wind power generation facilities (Lower Snake River, Hopkins Ridge 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. The Ferndale natural gas cogeneration facility was purchased in November 2012. This year is the first time the facility is included in PSE's GHG Inventory.

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 2012, about 32.9% of PSE's total electricity was generated by PSE and 67.1% was purchased (26.3% via firm contracts and 40.8% via non-firm contracts). 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 2012, PSE supplied natural gas to 763,655 customers in Western Washington. PSE purchases natural gas from natural gas producers in the United States and Canada, injects it into underground storage facilities, and withdraws it during the peak winter heating season. 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 direct CO_2 emissions from biomass fuels are accounted for and reported separately from the three scopes defined above. This is consistent with the GHG Protocol. The GHG Protocol specifies that these emissions should be accounted for separately because of the relatively quick interplay between biomass fuels and the terrestrial carbon stock. In contrast to biomass fuels, fossil fuels take a much longer time to develop, so the interaction between atmospheric carbon and fossil fuels is not considered in national GHG inventories.

Table 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 year's GHG inventory, SF_6 emissions from electrical transmission and distribution (T-D) equipment are included. PSE's CH_4 emissions from natural gas storage total approximately 0.08% of PSE's total emissions output, which is below the *de minimis* level of 2% that is recognized by the GHG Protocol and were excluded from Scope I emissions. PSE's electric and natural gas profile did not change in 2012. 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. 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 transmission and distribution. 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 includes SF_6 emissions from gas-insulated substations, circuit breakers, closed-pressure and hermetically sealed-pressure switchgear, gas-insulated lines containing SF_6, pressurized cylinders, gas carts, electric power transformers, and other containers of SF_6. On December 1, 2010, EPA finalized the GHG MRR Subpart DD to require calculation and reporting of these emissions. Therefore, the GHG inventory has included SF_6 emissions since

2011 to be consistent with the GHG MRR requirements. SF_6 emissions are very minor when compared to the total GHG emissions footprint.

- Emissions from equipment and materials used for construction, operation, and maintenance of PSE's electric system. This category includes incidental loss of HFCs and PFCs from refrigeration equipment and from incidental leaks of CH_4 at gas-fired turbines. Data regarding the use of PFCs and HFCs in refrigeration equipment and incidental leaks of CH_4 from gas-fired turbines were not available, and these were not considered in this inventory. Emissions of PFCs and HFCs from refrigeration equipment and CH_4 from incidental leaks at gas-fired turbines are extremely minor in relation to the emissions from the coal-combustion generation facilities.

4.2.1.2 Natural Gas Operations

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

4.2.1.3 Other Scope I Emissions

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

4.2.2 Scope II (Indirect Emissions from Electric Power)

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

4.2.3 Scope III (Other Indirect Emissions)

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

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

4.2.3.1 Electric Operations

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

4.2.3.2 Natural Gas Supply

PSE’s Scope III emissions associated with natural gas supply includes CO_2 emissions that would result from the complete use of natural gas provided to end-users on their distribution systems. End-users refer to customers that consume no more than 460,000 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, CO_2 emissions from the combustion of biomass were accounted for separately, as discussed in the introduction of Section 4.2.

5. Methodology

This inventory was compiled using data provided by PSE, calculation methodologies from WRI/WCBSD 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 (Direct Emissions)

5.1.1 Electric Operations

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

5.1.2 Natural Gas Operations

PSE's Scope I emissions from its natural gas distribution system were calculated using the GHG MRR Subpart W calculation methodologies (Table B-8). These emissions were calculated based on the number of leaking equipment identified from PSE's leak survey, M&R and T-D transfer 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)

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. 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 2009), *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 2012) (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 CO_2 emissions and the *Updated State-level Greenhouse Gas Coefficients for Electricity Generation 1998-2000* (DOE/EIA 2002) for CH_4 and N_2O emissions.

5.3.2 Natural Gas Supply

PSE's Scope III CO_2 emissions resulting from the complete combustion or oxidation of natural gas provided to end-users on PSE's distribution systems were calculated using the GHG MRR Subpart NN calculation methodologies (Table B-10). These emissions were calculated based on the amount of natural gas received at the city gate, less the amount delivered to downstream gas transmission pipelines and other local distribution companies (LDCs), less the amount delivered to customers that consume more than 460,000 Mscf of natural gas at a single facility per year, and plus the amount that bypassed the city gate and the 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. GHG Emissions

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

Table 6-1 Total Emissions by Scope

Table 6-2 Total Emissions by Scope in CO_2 Equivalents (CO_2e)

Table 6-3 Emissions from PSE-Owned Electric Operations

Table 6-4 Emissions from PSE-Owned Natural Gas Operations

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

Table 6-6 Detailed Emissions Calculations

7. 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 CO_2 emissions were from generated and purchased electricity (67.3%), while the remaining were from natural gas supply (32.7%). For $CH_{4,}$ the majority of emissions were from fugitive emissions from natural gas operations (83.2%). Generated and purchased electricity accounted for all N_2O emissions. SF_6 emissions from electrical T-D equipment were insignificant. The other two principal GHGs, HFCs and PFCs, were not quantified.

A 100-year global warming potential (GWP) (EPA 2009) (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 CO_2. A CO_2 equivalent (CO_2e) is calculated for each GHG so that GHG emissions can be compared on the same basis. In 2012, CO_2 emissions from generated and purchased electricity were the greatest source of GHGs emitted by PSE on a CO_2 equivalent basis (67.2%), followed by natural gas supply (32.4%).

Of PSE's electricity throughput (generated and purchased) in 2012, 32.9% was generated by PSE and 67.1% was purchased (26.3% via firm contracts and 40.8% via non-firm contracts) (Figure 7-1, Figure 7-2). Of the GHG emissions that are associated with electricity, 54.8% were from electricity generated by PSE and 45.2% were from electricity purchased (7.3% via firm contracts and 37.9% 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 46.8% 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 CO_2/kWh. Of CO_2 emissions from electricity generated by PSE (direct emissions), about 75.6% 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 71.7% 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 CO_2 emissions generated from firm contract purchased electricity come from coal-combustion generated and natural gas generated electric operations.

Third, regional average emission factors 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 2012 by source and the respective CO_2 emissions from each source. The largest source of electricity is hydroelectricity (37.0%), followed by coal (26.0%), natural gas/oil generated electricity (14.6%), wind power generated electricity (13.3%), other or unknown sources (8.7%), nuclear (0.3%), and biomass generated electricity (0.14%). The largest source of CO_2 emissions is from coal-combustion electricity generation (66.7%), followed by natural gas electricity generation (25.2%), other or unknown sources (7.7%), and biomass electricity generation (0.4%).

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 the 2012 GHG inventory as follows.

7.2.1 Potential Sources of GHG Emissions Not Included

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

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

7.2.2 Uncertainty Associated with Data Sources and Methodology

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

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

8. GHG Emissions Time Trends

8.1 Changes in Organizational and Operational 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. This year is the first time these facilities are included in PSE's GHG Inventory.

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 2011 (Table 8-3), PSE's total electricity throughput in 2012 decreased by 1,760,618 MWh (7%). GHG emissions in 2012 decreased by 456,137 metric tons CO_2e (4%). PSE's electricity generation increased by 490,583 MWh (6%). PSE's purchased electricity (firm contract and non-firm contract) decreased by 2,251,201 MWh (12%). The GHG emission intensity associated with PSE's electricity production decreased from 1.54 lb/kWh in 2011 to 1.48 lb/kWh in 2012. The GHG emission intensity associated with PSE's electricity purchases increased from 0.595 lb/kWh in 2011 to 0.599 lb/kWh in 2012. PSE's overall GHG emission intensity from generated and purchased electricity increased from 0.87 lb/kWh in 2011 to 0.89 lb/kWh in 2012.

The increase in PSE's electricity generation primarily reflects the combined decrease in electricity generation of 746,905 MWh (16%) from coal combustion facilities, and increase in electricity generation of 515,790 MWh (41%) from natural gas/oil generation facilities, 62,762 MWh (9%) from hydroelectric generation facilities, and 658,936 MWh (57%) from wind generation facilities. Among the four categories of PSE-generated electricity (hydro, coal, natural gas/oil, and wind), coal generation has the highest GHG emission intensity at 2.39 lb/kWh; natural gas/oil generation has a lower GHG emission intensity at 1.67 lb/kWh; both hydroelectric and wind generation essentially have a zero GHG emission intensity. The decrease in electricity generation from coal-combustion generation facilities (higher emission intensity), and increase in electricity generation from natural gas/oil generation facilities (relatively lower emission intensity), and hydroelectric and wind generation facilities (zero emission intensity), resulted in a decrease from 1.54 lb/kWh in 2011 to 1.48 lb/kWh in 2012 in overall GHG emission intensity associated with electricity generated by PSE.

The decrease in PSE's purchased electricity resulted primarily from a combination of a decrease in firm contract purchases of 1,585,875 MWh (21%) and PURPA purchases of 923,958 MWh (62%), and an increase in non-firm contract purchases of 253,790 MWh (3%) and biomass generated firm contract purchases of 4,843 MWh (30%). Among the four categories of purchased electricity (firm contract, PURPA, non-firm contract, and biomass), biomass, PURPA purchases, and non-firm contract purchases have higher GHG emission intensities of 2.69 lb/kWh, 0.89 lb/kWh, and 0.83 lb/kWh, respectively, while firm contract purchases have a lower GHG emission intensity of 0.18 lb/kWh. The combination of a decrease in firm contract purchased electricity (lower GHG emission intensities), decrease in PURPA purchased electricity (higher GHG emission intensities), and increase in non-firm contract and biomass generated firm contract purchased electricity (higher GHG emission intensities), resulted in an overall emission intensity for electricity purchased by PSE being the same compared to 2011.

8.3 Changes in Methodology

The methodology used in this year's GHG inventory is consistent with that used to prepare the 2011 inventory with some updates in emission factors.

8.3.1 All Emissions

In the 2009 GHG inventory, the Global Warming Potentials (GWP) for CH_4 and N_2O were updated from those provided in the *IPCC Fourth Assessment Report - Working Group I Report "The Physical Science Basis,"* (IPCC 2007) to those provided in the GHG MRR. Specifically, the GWP for CH_4 was updated from 21 to 23, while the GWP for N_2O was updated from 296 to 310. In this year's GHG inventory, there was no change to the GWP.

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 CH_4 and N_2O emissions from the coal-combustion generation facilities and a group of natural gas/oil generation facilities was changed from using AP-42 emission factors, fuel consumption, and a default high heating value to using the GHG MRR emission factors and unit-specific heat input (Table A-1, Table A-2). Also, for this group of natural gas/oil generation facilities, the methodology to quantify CO_2 emissions was changed from using AP-42 emission factors and fuel consumption to the 40 CFR Part 75 Appendix G method, which hourly CO_2 emissions are calculated using heat input rate measurements made with certified Appendix D fuel flow meters together with fuel-specific, carbon-based "F-factors". Second, the methodology to quantify CO_2, CH_4, and N_2O emissions for the remaining group of natural gas/oil generation facilities was changed from using AP-42 emission factors, fuel consumption, and a default high heating value, to using GHG MRR emission factors, fuel consumption, and unit-specific high heating values. This group of natural gas/oil generation facilities includes the Crystal Mountain, Fredonia 1 & 2, Frederickson 1 & 2, and Whitehorn 2 & 3 facilities.

In the 2011 and this year's GHG inventory, PSE's Scope I emissions also include SF_6 emissions from electricity transmission and distribution equipment. These emissions were calculated using the GHG MRR Subpart DD calculation methodologies (Table B-9).

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 Btu/ft^3 to 1,027 Btu/ft^3, as provided in the *Natural Gas Annual 2008* (DOE/EIA 2010). In the 2010 GHG inventory, the heating value was updated to 1,025 Btu/ft^3, as provided in the *Natural Gas Annual*

2009 (DOE/EIA 2010). In the 2011 GHG inventory, the calculation methodology to estimate PSE's Scope I emissions from natural gas operations was changed to align to that prescribed in the GHG MRR. GHG emissions from natural gas storage were removed, and GHG emissions from natural gas distribution were calculated using the GHG MRR Subpart W calculation methodologies. In this year's GHG inventory, there was no change in calculation methodology.

8.3.2.3 Other Scope I Emissions

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

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

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 (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 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 2004, 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 2007, the eGRID emission factor for calculating emissions from firm and non-firm contract purchases was updated. Specifically, the eGRID emission factor for CO_2 emissions was updated from 1.027 lb/MWh for the WECC subregion in EPA eGRID2007 Version 1.0 (EPA 2008), to 0.902 lb/MWh for the NWPP WECC Northwest subregion in *EPA eGRID2007 Version 1.1* (EPA 2008). In 2011, the eGRID emission factor for CO_2 emissions was updated to 0.859 lb/MWh for the NWPP WECC Northwest subregion in *EPA eGRID2010 Version 1.0* (EPA 2010). In this year's GHG inventory, the eGRID emission factor for CO_2 emissions was updated to 0.819 lb/MWh for the NWPP WECC Northwest subregion in *EPA eGRID2012 Version 1.0* (EPA 2012).

In 2010, 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 this year's 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: 9,200 Btu/kWh to 8,800 Btu/kWh for coal, 10,788 Btu/kWh to 10,745 Btu/kWh for semi-closed gas turbine (SCGT), 6,752 Btu/kWh to 6,430 Btu/kWh for combined cycle gas turbine (CCGT), 9,451 Btu/kWh to 13,500 Btu/kWh for biomass, and 10,788 Btu/kWh to 10,745 Btu/kWh for petroleum.

8.3.3.2 Natural Gas Supply

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

9. GHG Emissions in Comparison to Other Electric Utilities

The 2012 *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States Report* was released in July 2012 through a collaborative effort by Ceres, the Natural Resources Defense Council (NRDC), Public Service Enterprise Group (PSEG), and the Pacific Gas & Electric (PG&E) Corporation. The report examines and compares the air pollutant emissions of the 100 largest power producers in the U.S. based on 2008 plant ownership and emissions data that are available to the public through several databases maintained by state and federal agencies.

The CO_2 emission intensities (lb/kWh) published in the 2012 Benchmarking Report and those calculated in this report show good agreement. The 2012 Benchmarking Report indicates that PSE's 2010 CO_2 emission intensities for all generating sources and coal-fired generation are 1.42 lb/kWh and 2.31 lb/kWh, respectively. The CO_2 emission intensities calculated in the 2010 inventory for all generating sources and coal-fired generation were 1.54 lb/kWh and 2.17 lb/kWh, respectively. In 2011, the CO_2 emission intensities calculated for all generating sources and coal-fired generation are 1.54 lb/kWh and 2.19 lb/kWh, respectively. In this year's GHG inventory, the CO_2 emission intensities calculated for all generating sources and coal-fired generation are 1.48 lb/kWh and 2.39 lb/kWh, respectively.

Among the 100 largest U.S. electric producers in 2010, PSE ranked 76th in total generation and 61th in coal-fired generation. For total CO_2 emissions, PSE ranked 64th. In terms of CO_2 emissions intensity, PSE ranked 47th in all generating sources. PSE's emission intensity from Colstrip, when compared to other utility's coal-only resources, ranked 16th. 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 CO_2 emissions intensity was compared to other utilities graphically in Figure 9-1. PSE's emissions from electricity generation are moderate as compared to other electric producers. PSE's overall CO_2 emissions 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. 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 339,500,000 kWh of electricity and 5,205,000 therms of natural gas in 2012. 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 Northwest Power Pool is a combined cycle gas turbine (CCGT) rated at approximately 7,000 Btu/kWh. Using this assumption, these electric conservation measures amounted to avoided emissions of over 115,829 metric tons of CO_2, 0.28 metric tons of CH_4, and 0.23 metric tons of N_2O in 2012. PSE's natural gas conservation measures amounted to an avoidance of emissions of approximately 32.61 metric tons of CH_4 in 2012.

11. References

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Appendix A

Tables and Figures

Table 4-1. Calendar Year 2012 Sources of Emissions Accounted

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Operational Boundary	Greenhouse Gases					
	CO_2	CH_4	N_2O	SF_6	HFCs (3)	PFCs (3)
Scope I (Direct Emissions)						
Emissions from PSE-Owned Electric Operations	X	X	X (1)	X		
Emissions from PSE-Owned Natural Gas Operations	X	X				
Emissions from Fleet Vehicle Use (4)						
Scope II (Indirect Emissions)						
Emissions from Purchased Electricity Used by PSE	X (2)	X (2)	X (2)			
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) Except Crystal (no emission factors available).
(2) Included in Scope I and Scope III. Not reported in Scope II.
(3) HFCs and PFCs are not included in this inventory because PSE's emissions of these GHGs are negligible.
(4) PSE elected not to calculate emissions from fleet vehicles as they are minimal.

Table 6-1. Total Emissions by Scope

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Emission Source	**Energy Amount** (UOM)	**Emissions**								**Emission Intensity**			
		CO_2		**CH_4**		**N_2O**		**SF_6**		**CO_2** (UOM)	**CH_4** (UOM)	**N_2O** (UOM)	**SF_6** (UOM)
		(metric ton)	(%) (3)	(metric ton)	(%) (3)	(metric ton)	(%) (3)	(metric ton)	(%) (3)				
Scope I													
Electric Operations													
Hydro	746,739,664 kWh	0	0%	0	0%	0	0%	0	0%	0 lb/kWh	0 lb/kWh	0 lb/kWh	0 lb/kWh
Coal	3,809,524,012 kWh	4,107,969	75.6%	402	14%	58	94%	0	0%	2.4 lb/kWh	2.3E-04 lb/kWh	3.4E-05 lb/kWh	0 lb/kWh
Natural Gas/ Oil	1,758,794,382 kWh	1,328,010	24%	29	1%	3.6	6%	0	0%	1.7 lb/kWh	3.6E-05 lb/kWh	4.5E-06 lb/kWh	0 lb/kWh
Wind	1,822,813,069 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%	-0.005	100%	NC	NC	NC	NC
Total Scope I - PSE-owned Electric Operations	**8,137,871,127 kWh**	**5,435,979**	**100%**	**430**	**15%**	**62**	**100%**	**-0.005**	**100%**	**1.5 lb/kWh**	**0.0001 lb/kWh**	**0.00002 lb/kWh**	**0 lb/kWh**
Natural Gas Operations													
Distribution	903,534,000 thm	76	0%	2,469	85%	0	0%	0	NC	1.9E-04 lb/thm	6.0E-03 lb/thm	0 lb/thm	0 lb/thm
Total Scope I - PSE-owned Natural Gas Operations	**903,534,000 thm**	**76**	**0%**	**2469**	**85%**	**0**	**0%**	**0**	**NC**	**0.0002 lb/thm**	**0.006 lb/thm**	**0 lb/thm**	**0 lb/thm**
Total Scope I		**5,436,055**	**100%**	**2,899**	**100%**	**62**	**100%**	**-0.005**	**100%**				
Scope III													
Electric Operations													
Firm Contracts	6,486,527,488 kWh	698,286	8%	16	23%	15	15%	0	NC	0.2 lb/kWh	5.E-06 lb/kWh	5.E-06 lb/kWh	0 lb/kWh
Non-Firm Contracts (1)	10,112,471,880 kWh	3,757,706	41%	51	77%	88	85%	0	NC	0.8 lb/kWh	1.E-05 lb/kWh	2.E-05 lb/kWh	0 lb/kWh
Total Scope III - Electricity Purchases	**16,598,999,368 kWh**	**4,455,991**	**48%**	**67**	**100%**	**103**	**100%**	**0**	**NC**	**1 lb/kWh**	**0 lb/kWh**	**0 lb/kWh**	**0 lb/kWh**
Natural Gas Supply													
Supply to End-Users	875,121,331 thm	4,813,167	52%	0	0%	0	0%	0	NC	12 lb/thm	0 lb/thm	0 lb/thm	0 lb/thm
Total Scope III - Natural Gas Supply	**875,121,331 thm**	**4,813,167**	**52%**	**0**	**0%**	**0**	**0%**	**0**	**NC**	**12 lb/thm**	**0 lb/thm**	**0 lb/thm**	**0 lb/thm**
Total Scope III		**9,269,159**	**100%**	**67**	**100%**	**103**	**100%**	**0**	**NC**				
Outside Scope													
Biomass - Firm Contract Purchases (2)	21,142,417 kWh	25,246	100%	0	NC	0	NC	0	NC	2.6 lb/kWh	0 lb/kWh	0 lb/kWh	0 lb/kWh
Total Outside Scope		**25,246**	**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 CO_2 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 - 2012 Greenhouse Gas Inventory

Emission Source	Energy Amount	(UOM)	Emissions in CO_2 Equivalents (CO_2e) - 100-Year Timeframe (Tons)										Emission Intensity Total	(UOM)
			CO_2		CH_4		N_2O		SF_6		Total			
			(metric ton)	(%) (3)	(metric ton)	(%) (3)	(metric ton)	(%) (3)	(metric ton)	(%) (3)	(metric ton)	(%) (3)		
Scope I														
Electric Operations														
Hydro	746,739,664	kWh	0	0%	0	0%	0	0%	0	0%	0	0%	0	lb/kWh
Coal	3,809,524,012	kWh	4,107,969	74%	8,436	0.2%	18,114	0.3%	0	0%	4,134,519	75%	2.4	lb/kWh
Natural Gas/ Oil	1,758,794,382	kWh	1,328,010	24%	599	0.01%	1,105	0.02%	0	0%	1,329,713	24%	1.7	lb/kWh
Wind	1,822,813,069	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%	-108	-0.002%	-108	-0.002%	NC	
Total Scope I - PSE-owned Electric Operations	**8,137,871,127**	**kWh**	**5,435,979**	**99%**	**9,035**	**0.2%**	**19,219**	**0.3%**	**-108**	**-0.002%**	**5,464,124**	**99%**	**1.5**	**lb/kWh**
Natural Gas Operations														
Distribution	903,534,000	thm	76	0.001%	51,840	1%	0	0%	0	0%	51,917	1%	0.1	lb/thm
Total Scope I - PSE-owned Natural Gas Operations	**903,534,000**	**thm**	**76**	**0.001%**	**51,840**	**1%**	**0**	**0%**	**0**	**0%**	**51,917**	**1%**	**0.1**	**lb/thm**
Total Scope I			**5,436,055**	**99%**	**60,875**	**1%**	**19,219**	**0.3%**	**-108**	**-0.002%**	**5,516,041**	**100%**		
Scope III														
Electric Operations														
Firm Contracts	6,486,527,488	kWh	698,286	8%	328	0.004%	4,699	0.1%	0	0%	703,312	8%	0.2	lb/kWh
Non-Firm Contracts (1)	10,112,471,880	kWh	3,757,706	40%	1,069	0.01%	27,302	0.3%	0	0%	3,786,077	41%	0.8	lb/kWh
Total Scope III - Electricity Purchases	**16,598,999,368**	**kWh**	**4,455,991**	**48%**	**1,397**	**0.02%**	**32,001**	**0.3%**	**0**	**0%**	**4,489,389**	**48%**	**0.6**	**lb/kWh**
Natural Gas Supply														
Supply to End-Users	875,121,331	thm	4,813,167	52%	0	0%	0	0%	0	0%	4,813,167	52%	12.1	lb/thm
Total Scope III - Natural Gas Supply	**875,121,331**	**thm**	**4,813,167**	**52%**	**0**	**0%**	**0**	**0%**	**0**	**0%**	**4,813,167**	**52%**	**12.1**	**lb/thm**
Total Scope III			**9,269,159**	**100%**	**1,397**	**0.02%**	**32,001**	**0.3%**	**0**	**0%**	**9,302,556**	**100%**		
Outside Scope														
Biomass - Firm Contract Purchases (2)	21,142,417	kWh	25,246	100%	0	0%	0	0%	0	0%	25,246	100%	2.6	lb/kWh
Total Outside Scope			**25,246**	**100%**	**0**	**0%**	**0**	**0%**	**0**	**0%**	**25,246**	**100%**		

Data Source:

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

Global Warming Potentials [1]:

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

Note(s):

(1) Non-firm contract purchases do not include "Book Outs" under EITF Issue 03-11.

(2) Consistent with the GHG Protocol, only CO_2 is accounted separately for biomass generation.

(3) Percentage of emissions in CO_2e in scope.

(4) NC = Not calculated.

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

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Emission Source	Energy Amount [1] (kWh)	PSE Share [2] (%)	PSE Share of Emissions (1)								Emission Intensity			
			CO_2		CH_4		N_2O		SF_6		CO_2	CH_4	N_2O	SF_6
			(metric ton)	(%) (5)	(metric ton)	(%) (5)	(metric ton)	(%) (5)	(metric ton)	(%) (5)	(lb/kWh)	(lb/kWh)	(lb/kWh)	(lb/kWh)
Hydro														
Hydro	746,739,664	100%	0	0%	0	0%	0	0%	0	0%	0	0	0	0
Total Hydro	**746,739,664**		**0**	**0%**	**0**	**0%**	**0**	**0%**	**0**	**0%**	**0**	**0**	**0**	**0**
Coal (2)														
Colstrip Unit 1	766,272,013	50%	737,857	14%	70	16%	10	17%	0	0%	2.1	2.0E-04	2.9E-05	0
Colstrip Unit 2	658,062,999	50%	780,290	14%	73	17%	11	17%	0	0%	2.6	2.5E-04	3.6E-05	0
Colstrip Unit 3	1,067,797,997	25%	1,261,919	23%	124	29%	18	29%	0	0%	2.6	2.6E-04	3.7E-05	0
Colstrip Unit 4	1,317,391,003	25%	1,327,904	24%	134	31%	19	31%	0	0%	2.2	2.2E-04	3.3E-05	0
Total Coal	**3,809,524,012**		**4,107,969**	**76%**	**402**	**93%**	**58**	**94%**	**0**	**0%**	**2.4**	**2.3E-04**	**3.4E-05**	**0**
Natural Gas/ Oil (3)														
Crystal Mountain	298,260	100%	9,819	0%	0.4	0.1%	0.1	0.1%	0	0%	73	2.9E-03	5.9E-04	0
Encogen 1	27,894,499	100%	18,221	0%	0.3	0.1%	0.03	0.1%	0	0%	1.4	2.7E-05	2.7E-06	0
Encogen 2	23,516,334	100%	16,825	0%	0.3	0.1%	0.03	0.1%	0	0%	1.6	2.9E-05	2.9E-06	0
Encogen 3	24,480,582	100%	16,580	0%	0.3	0.1%	0.03	0.05%	0	0%	1.5	2.8E-05	2.8E-06	0
Ferndale 1	581,098	100%	7,052	0%	0.1	0.03%	0.01	0.02%	0	0%	27	5.0E-04	5.0E-05	0
Ferndale 2	502,592	100%	7,258	0%	0.1	0.03%	0.01	0.02%	0	0%	32	5.9E-04	5.9E-05	0
Frederickson 1	16,097,306	100%	23,455	0%	0.6	0.1%	0.1	0.2%	0	0%	3.2	8.7E-05	1.4E-05	0
Frederickson 2	15,553,004	100%	19,536	0%	0.5	0.1%	0.1	0.1%	0	0%	2.8	6.4E-05	8.7E-06	0
Fredonia 1	10,750,524	100%	41,302	1%	1.5	0.4%	0.3	0.5%	0	0%	8.5	3.1E-04	5.9E-05	0
Fredonia 2	6,442,194	100%	73,109	1%	2.9	0.7%	0.6	0.9%	0	0%	25	9.9E-04	2.0E-04	0
Fredonia 3	10,918,307	100%	6,418	0%	0.1	0.03%	0.01	0.02%	0	0%	1.3	2.4E-05	2.4E-06	0
Fredonia 4	14,441,693	100%	8,155	0%	0.1	0.03%	0.01	0.02%	0	0%	1.2	2.3E-05	2.3E-06	0
Frederickson 1	115,617,141	49.85%	138,997	3%	2.6	0.6%	0.3	0.4%	0	0%	2.7	4.9E-05	4.9E-06	0
Goldendale	596,431,626	100%	325,355	6%	6.0	1.4%	0.6	1.0%	0	0%	1.2	2.2E-05	2.2E-06	0
Mint Farm	708,885,967	100%	433,428	8%	8.0	1.9%	0.8	1.3%	0	0%	1.3	2.5E-05	2.5E-06	0
Sumas	157,105,554	100%	106,537	2%	2.0	0.5%	0.2	0.3%	0	0%	1.5	2.8E-05	2.8E-06	0
Whitehorn 2	15,884,501	100%	35,482	1%	1.1	0.3%	0.2	0.3%	0	0%	4.9	1.6E-04	2.8E-05	0
Whitehorn 3	13,393,199	100%	40,480	1%	1.4	0.3%	0.3	0.4%	0	0%	6.7	2.3E-04	4.2E-05	0
Total Natural Gas/ Oil	**1,758,794,382**		**1,328,010**	**24%**	**29**	**7%**	**3.6**	**6%**	**0**	**0%**	**1.7**	**3.6E-05**	**4.5E-06**	**0**
Wind														
Wild Horse	677,389,930	100%	0	0%	0	0%	0	0%	0	0%	0	0	0	0
Lower Snake River	714,783,177	100%	0	0%	0	0%	0	0%	0	0%	0	0	0	0
Hopkins Ridge	430,639,962	100%	0	0%	0	0%	0	0%	0	0%	0	0	0	0
Total Wind	**1,822,813,069**		**0**	**0%**	**0**	**0%**	**0**	**0%**	**0**	**0%**	**0**	**0**	**0**	**0**
Electrical Transmission and Distribution Equipment (4)														
All equipment	0	100%	0	0%	0	0%	0	0%	-0.005	100%	NC	NC	NC	NC
Total Electrical Transmission and Distribution Equipment			**0**	**0%**	**0**	**0%**	**0**	**0%**	**-0.005**	**100%**	**NC**	**NC**	**NC**	**NC**
Total PSE-Owned Electric Operations	**8,137,871,127**		**5,435,979**	**100%**	**430**	**100%**	**62**	**100%**	**-0.005**	**100%**	**1.5**	**1.E-04**	**2.E-05**	**-1.E-09**

Data Source:

[1] PSE 2012 Summary of Generation (PSE February 2013).
[2] PSE 2012 Form 10-K (PSE 2012).

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 - 2012 Greenhouse Gas Inventory

Emission Source	Count	Emissions (2)				Emissions in CO_2 Equivalents (CO_2e) - 100-Year Timeframe (Tons) (2)					
		CO_2		CH_4		CO_2		CH_4		Total	
		(metric ton)	(%) (3)	(metric ton)	(%) (3)	(metric ton)	(%) (4)	(metric ton)	(%) (4)	(metric ton)	(%) (4)
T-D Transfer Station [1],(1)											
Connector	0	0	0%	0	0%	0	0%	0	0%	0	0%
Block Valve	0	0	0%	0	0%	0	0%	0	0%	0	0%
Control Valve	0	0	0%	0	0%	0	0%	0	0%	0	0%
Pressure Relief Valve	0	0	0%	0	0%	0	0%	0	0%	0	0%
Orifice Meter	0	0	0%	0	0%	0	0%	0	0%	0	0%
Regulator	0	0	0%	0	0%	0	0%	0	0%	0	0%
Open-ended Line	0	0	0%	0	0%	0	0%	0	0%	0	0%
Total T-D Transfer Station	**0**	**0**	**0%**	**0**	**0%**	**0**	**0%**	**0**	**0%**	**0**	**0%**
Below Grade M&R Station [2]											
Below Grade M&R Station Components > 300 psig	2	0.01	0.02%	0.4	0.02%	0.01	0.00003%	9	0.02%	9	0.02%
Below Grade M&R Station Components 100 - 300 psig	354	0.36	0.5%	12	0.5%	0.36	0.001%	244	0.5%	244	0.5%
Below Grade M&R Station Components < 100 psig	35	0.02	0.02%	1	0.02%	0.02	0.00003%	12	0.02%	12	0.02%
Total Below Grade M&R Station	**391**	**0.4**	**1%**	**13**	**1%**	**0.39**	**0%**	**265**	**1%**	**265**	**1%**
Distribution Mains [2]											
Unprotected Steel	25	1.59	2%	52	2%	1.59	0.003%	1,083	2%	1,085	2%
Protected Steel	3,853	6.84	9%	221	9%	6.84	0.01%	4,644	9%	4,651	9%
Plastic	8,197	46.95	62%	1,519	62%	46.95	0.1%	31,898	61%	31,945	62%
Cast Iron	7	0.97	1%	31	1%	0.97	0.002%	657	1%	658	1%
Total Distribution Mains	**12,082**	**56**	**74%**	**1,823**	**74%**	**56.34**	**0.1%**	**38,282**	**74%**	**38,338**	**74%**
Distribution Services [2]											
Unprotected Steel	500	0.48	1%	16	1%	0.48	0.001%	327	1%	328	1%
Protected Steel	155,764	15.79	21%	511	21%	15.79	0.03%	10,728	21%	10,744	21%
Plastic	648,935	3.29	4%	106	4%	3.29	0.01%	2,235	4%	2,238	4%
Copper	35	0.01	0.01%	0.2	0.01%	0.01	0.00001%	4	0.01%	4	0.01%
Total Distribution Services	**805,234**	**20**	**26%**	**633**	**26%**	**19.57**	**0.04%**	**13,294**	**26%**	**13,313**	**26%**
Total PSE-Owned Natural Gas Operations		**76**	**100%**	**2,469**	**100%**	**76**	**0.1%**	**51,840**	**100%**	**51,917**	**100%**

Data Source:

[1] PSE 2011 Leak Detection Survey.

[2] PSE.

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

Global Warming Potentials [3]**:**

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

Note(s):

(1) Count represents number of leaking components.

(2) See Table B-8 for calculation details.

(3) Percentage of emissions among PSE-owned natural gas operations.

(4) Percentage of emissions in CO_2e among PSE-owned natural gas operations.

(5) NC = Not calculated.

(6) M&R = Metering-regulating.

(7) T-D = Transmission-distribution.

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

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Non-Firm Contract Purchased Electricity: 10,112,471,880 kWh

Emission Source	Emissions		
	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)
Non-Firm Contract Purchased Electricity	3,757,706	50.92	88.07

Emission Factors:

Fuel Type	CO_2 (lb/kWh)		CH_4 (lb/kWh)		N_2O (lb/kWh)	
Other (1)	0.819	[1]	1.11E-05	[2]	1.92E-05	[2]

Data Source:

[1] eGRID2010 Version 1.1 (EPA May 2011).

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

Note(s):

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

Table 6-6. Detailed Emissions Calculations

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Emission Source	Energy Amount (kWh)	Total						Coal					Natural Gas					Hydro		Nuclear		Biomass					Petroleum					Wind		Solar		Other				
		% of Total Power	% of Generation or Purchase	Total CO_2 (metric ton)	Total CH_4 (metric ton)	Total N_2O (metric ton)	Total CO_2e (metric ton)	% of Generation	Power (kWh)	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)	% of Generation	Power (kWh)	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)	% of Generation	Power (kWh)	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)
PSE GENERATION																																								
Hydro [1]	746,739,664	3.0%	9.2%	0	0	0	0		0	0	0	0		0	0	0	0		746,739,664		0		0	0	0	0		0	0	0	0		0				0	0	0	0
	746,739,664	3.0%	9.2%	0	0	0	0											100.00%	746,739,664																					
Coal [2]	3,809,524,012	15.4%	46.8%	4,107,969	401.7	58.4	4,134,519		3,809,524,012	4,107,969	402	58		0	0	0	0		0		0		0	0	0	0		0	0	0	0		0				0	0	0	0
	766,272,013	3.1%	9.4%	737,856.5	70.4	10.2	742,510	100.00%	766,272,013	737,857	70	10																												
	658,062,999	2.7%	8.1%	780,289.9	73.2	10.6	785,128	100.00%	658,062,999	780,290	73	11																												
	1,067,797,997	4.3%	13.1%	1,261,919.2	124.5	18.1	1,270,147	100.00%	1,067,797,997	1,261,919	124	18																												
	1,317,391,003	5.3%	16.2%	1,327,903.8	133.6	19.4	1,336,734	100.00%	1,317,391,003	1,327,904	134	19																												
Natural Gas/ Oil [1],(3)	1,758,794,382	7.1%	21.6%	1,328,010	28.5	3.6	1,329,713		0	0	0	0		1,758,794,382	1,328,010	29	4		0		0		0	0	0	0		0	0	0	0		0				0	0	0	0
	298,260	0.0%	0.0%	9,818.8	0.4	0.1	9,852						100.00%	298,260	9,819	0.40	0.08																							
	27,894,499	0.1%	0.3%	18,220.5	0.3	0.0	18,238						100.00%	27,894,499	18,221	0.34	0.03																							
	23,516,334	0.1%	0.3%	16,825.5	0.3	0.0	16,842						100.00%	23,516,334	16,825	0.31	0.03																							
	24,480,582	0.1%	0.3%	16,580.2	0.3	0.0	16,596						100.00%	24,480,582	16,580	0.31	0.03																							
	581,098	0.0%	0.0%	7,052.0	0.1	0.0	7,059						100.00%	581,098	7,052	0.13	0.01																							
	502,592	0.0%	0.0%	7,258.1	0.1	0.0	7,265						100.00%	502,592	7,258	0.13	0.01																							
	16,097,306	0.1%	0.2%	23,454.9	0.6	0.1	23,499						100.00%	16,097,306	23,455	0.63	0.10																							
	15,553,004	0.1%	0.2%	19,535.7	0.5	0.1	19,564						100.00%	15,553,004	19,536	0.45	0.06																							
	10,750,524	0.0%	0.1%	41,302.4	1.5	0.3	41,423						100.00%	10,750,524	41,302	1.51	0.29																							
	6,442,194	0.0%	0.1%	73,108.7	2.9	0.6	73,346						100.00%	6,442,194	73,109	2.88	0.57																							
	10,918,307	0.0%	0.1%	6,418.3	0.1	0.0	6,424						100.00%	10,918,307	6,418	0.12	0.01																							
	14,441,693	0.1%	0.2%	8,154.6	0.1	0.0	8,162						100.00%	14,441,693	8,155	0.15	0.01																							
	115,617,141	0.5%	1.4%	138,996.9	2.6	0.3	139,131						100.00%	115,617,141	138,997	2.58	0.26																							
	596,431,626	2.4%	7.3%	325,354.9	6.0	0.6	325,669						100.00%	596,431,626	325,355	6.03	0.60																							
	708,885,967	2.9%	8.7%	433,428.1	8.0	0.8	433,846						100.00%	708,885,967	433,428	8.04	0.80																							
	157,105,554	0.6%	1.9%	106,537.2	2.0	0.2	106,640						100.00%	157,105,554	106,537	1.98	0.20																							
	15,884,501	0.1%	0.2%	35,482.3	1.1	0.2	35,569						100.00%	15,884,501	35,482	1.14	0.20																							
	13,393,199	0.1%	0.2%	40,480.4	1.4	0.3	40,588						100.00%	13,393,199	40,480	1.38	0.25																							
Wind [1]	1,822,813,069	7.4%	22.4%	0.0	0.0	0.0	0		0	0	0	0		0	0	0	0		0		0		0	0	0	0		0	0	0	0		1,822,813,069				0	0	0	0
	677,389,930	2.7%	8.3%	0	0	0	0																									100.00%	677,389,930							
	714,783,177	2.9%	8.8%	0	0	0	0																									100.00%	714,783,177							
	430,639,962	1.7%	5.3%	0	0	0	0																									100.00%	430,639,962							
Total PSE Generation	8,137,871,127	32.9%	100.0%	5,435,979	430	62	5,464,233	46.81%	3,809,524,012	4,107,969	402	58	21.61%	1,758,794,382	1,328,010	29	4	9.18%	746,739,664	0%	0	0%	0	0	0	0	0%	0	0	0	0	22.40%	1,822,813,069	0	0	0.00%	0	0	0	0
PURCHASES [1]																																								
FIRM CONTRACT PURCHASES																																								
Hydro	4,190,220,868	16.9%	25.2%	0	0	0	0		0	0	0	0		0	0	0	0		4,190,220,868		0		0	0	0	0		0	0	0	0		0		0		0	0	0	0
	21,416,769	0.1%	0.1%	0	0	0	0											100.00%	21,416,769																					
	11,481,120	0.0%	0.1%	0	0	0	0											100.00%	11,481,120																					
	2,300,840,000	9.3%	13.8%	0	0	0	0											100.00%	2,300,840,000																					
	0	0.0%	0.0%	0	0	0	0											100.00%	0																					
	716,417,000	2.9%	4.3%	0	0	0	0											100.00%	716,417,000																					
	-80,276,000	-0.3%	-0.5%	0	0	0	0											100.00%	-80,276,000																					
	979,910,000	4.0%	5.9%	0	0	0	0											100.00%	979,910,000																					
	75,568,000	0.3%	0.5%	0	0	0	0											100.00%	75,568,000																					
	120,000,000	0.5%	0.7%	0	0	0	0											100.00%	120,000,000																					
	6,421,800	0.0%	0.0%	0	0	0	0											100.00%	6,421,800																					
	215,179	0.0%	0.0%	0	0	0	0											100.00%	215,179																					
	38,227,000	0.2%	0.2%	0	0	0	0											100.00%	38,227,000																					
Wind	125,148,267	0.5%	0.8%	0	0	0	0		0	0	0	0		0	0	0	0		0		0		0	0	0	0		0	0	0	0		125,148,267		0		0	0	0	0
	190,138	0.0%	0.0%	0	0	0	0																									100.00%	190,138							
	124,794,000	0.5%	0.8%	0	0	0	0																									100.00%	124,794,000							
	134,729	0.0%	0.0%	0	0	0	0																									100.00%	134,729							
	29,400	0.0%	0.0%	0	0	0	0																									100.00%	29,400							
Solar	61,410	0.0002%	0.0004%	0	0	0	0		0	0	0	0		0	0	0	0		0		0		0	0	0	0		0	0	0	0		0		61,410		0	0	0	0
	3,480	0.0000%	0.0000%	0	0	0	0																											100.00%	3,480					
	57,930	0.0002%	0.0003%	0	0	0	0																											100.00%	57,930					
Other	1,614,073,000	6.5%	9.7%	474,849	6.4	11.1	478,431		0	0	0	0		1,200,459	719	0	0		292,911,996		41,615,912		0	0	0	0		0	0	0	0		2,400,918		0		1,275,943,715	474,129	6	11
	217,875,000	0.9%	1.3%	80,960.4	1.1	1.9	81,572																													100.00%	217,875,000	80,960	1	2
	6,832,000	0.0%	0.0%	2,538.7	0.0	0.1	2,558																													100.00%	6,832,000	2,539	0	0
	400,153,000	1.6%	2.4%	23,766.8	0.3	0.5	23,944						0.30%	1,200,459	719	0	0	73.20%	292,911,996	10.40%	41,615,912											0.60%	2,400,918			15.50%	62,023,715	23,047	0	1
	549,589,000	2.2%	3.3%	204,222.4	2.8	4.8	205,764																													100.00%	549,589,000	204,222	3	5
	500,000	0.0%	0.0%	185.8	0	0	187																													100.00%	500,000	186	0	0
	439,124,000	1.8%	2.6%	163,174.6	2.2	3.8	164,407																													100.00%	439,124,000	163,175	2	4
Biomass	21,142,417	0.1%	0.1%	25,246	2.7	1.7	25,825		0	0	0	0		0	0	0	0		0		0		21,142,417	25,246	3	2		0	0	0	0		0		0		0	0	0	0
	1,390,963	0.0%	0.0%	1,660.9	0.2	0.1	1,699															100.00%	1,390,963	1,661	0	0														
	4,187,861	0.0%	0.0%	5,000.7	0.5	0.3	5,115															100.00%	4,187,861	5,001	1	0														
	5,803,073	0.0%	0.0%	6,929.4	0.7	0.5	7,088															100.00%	5,803,073	6,929	1	0														
	3,402,000	0.0%	0.0%	4,062.3	0.4	0.3	4,155															100.00%	3,402,000	4,062	0	0														
	58,277	0.0%	0.0%	69.6	0.0	0.0	71															100.00%	58,277	70	0	0														
	2,762,123	0.0%	0.0%	3,298.2	0.4	0.2	3,374															100.00%	2,762,123	3,298	0	0														
	3,538,120	0.0%	0.0%	4,224.8	0.5	0.3	4,322															100.00%	3,538,120	4,225	0	0														
PURPA Firm Contracts	557,023,943	2.2%	3.4%	223,437	6.4	2.4	224,302		0	0	0	0		371,976,232	222,889	6	2		183,477,024		0		0	0	0	0		0	0	0	0		0		95680		1,475,007	548	0	0
	2,787,312	0.0%	0.0%	1,670.2	0.0	0.0	1,677						100.00%	2,787,312	1,670	0	0																							
	1,243,960	0.0%	0.0%	0.0	0.0	0.0	0											100.00%	1,243,960																					
	42,519,240	0.2%	0.3%	0.0	0.0	0.0	0											100.00%	42,519,240																					
	95,680	0.0%	0.0%	0.0	0.0	0.0	0																											100.00%	95,680					
	369,188,920	1.5%	2.2%	221,218.6	6.4	2.3	222,073						100.00%	369,188,920	221,219	6	2																							
	0	0.0%	0.0%	0.0	0.0	0.0	0						100.00%	0	0	0	0																							
	25,294,784	0.1%	0.2%	0.0	0.0	0.0	0											100.00%	25,294,784																					
	1,475,007	0.0%	0.0%	548.1	0.0	0.0	552																													100.00%	1,475,007	548	0	0
	1,478,240	0.0%	0.0%	0.0	0.0	0.0	0											100.00%	1,478,240																					
	0	0.0%	0.0%	0.0	0.0	0.0	0						100.00%	0	0	0	0																							
	95,827,200	0.4%	0.6%	0.0	0.0	0.0	0											100.00%	95,827,200																					
	17,113,600	0.1%	0.1%	0.0	0.0	0.0	0											100.00%	17,113,600																					
Total - Firm Contracts	6,507,669,905	26.3%	39.2%	723,532	16	15	728,558	0%	0	0	0	0	5.73%	373,176,691	223,608	6	2	71.71%	4,666,609,888	0.64%	41,615,912	0.32%	21,142,417	25,246	3	2	0%	0	0	0	0	1.96%	127,549,185	0	157,090	19.63%	1,277,418,722	474,678	6	11

Table 6-6. Detailed Emissions Calculations

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Emission Source	Energy Amount	Total						Coal					Natural Gas					Hydro		Nuclear		Biomass					Petroleum					Wind		Solar		Other				
	(kWh)	% of Total Power	% of Generation or Purchase	Total CO_2 (metric ton)	Total CH_4 (metric ton)	Total N_2O (metric ton)	Total CO_2e (metric ton)	% of Generation	Power (kWh)	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)	% of Generation	Power (kWh)	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)	% of Generation	Power (kWh)	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	% of Generation	Power (kWh)	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)
NON-FIRM CONTRACT PURCHASES																																								
> 100,000,000 kWh	10,975,287,880	44.3%	66.0%																																					
	1,404,952,000	5.7%	8.5%																																					
	1,278,611,000	5.2%	7.7%																																					
	1,236,010,000	5.0%	7.4%																																					
	1,078,306,000	4.4%	6.5%																																					
	1,014,046,000	4.1%	6.1%																																					
	561,582,000	2.3%	3.4%																																					
	502,043,000	2.0%	3.0%																																					
	467,588,000	1.9%	2.8%																																					
	457,673,000	1.8%	2.8%																																					
	384,112,700	1.6%	2.3%																																					
	336,342,000	1.4%	2.0%																																					
	269,356,000	1.1%	1.6%																																					
	252,059,000	1.0%	1.5%																																					
	246,052,000	1.0%	1.5%																																					
	231,003,000	0.9%	1.4%																																					
	222,630,000	0.9%	1.3%																																					
	200,033,000	0.8%	1.2%																																					
	182,238,000	0.7%	1.1%																																					
	176,041,000	0.7%	1.1%																																					
	126,962,180	0.5%	0.8%																																					
	124,383,000	0.5%	0.7%																																					
	113,935,000	0.5%	0.7%																																					
	109,330,000	0.4%	0.7%																																					
< 100,000,000 > 20,000,000 kWh	483,676,000	2.0%	2.9%																																					
	76,562,000	0.3%	0.5%																																					
	70,000,000	0.3%	0.4%																																					
	65,386,000	0.3%	0.4%																																					
	62,658,000	0.3%	0.4%																																					
	42,962,000	0.2%	0.3%																																					
	36,506,000	0.1%	0.2%																																					
	32,812,000	0.1%	0.2%																																					
	26,743,000	0.1%	0.2%																																					
	24,419,000	0.1%	0.1%																																					
	23,628,000	0.1%	0.1%																																					
	22,000,000	0.1%	0.1%																																					
< 20,000,000 kWh > 1,000,000 kWh	40,515,000	0.2%	0.2%																																					
	11,019,000	0.0%	0.1%																																					
	10,082,000	0.0%	0.1%																																					
	3,654,000	0.0%	0.0%																																					
	3,418,000	0.0%	0.0%																																					
	3,343,000	0.0%	0.0%																																					
	2,400,000	0.0%	0.0%																																					
	1,600,000	0.0%	0.0%																																					
	1,487,000	0.0%	0.0%																																					
	1,200,000	0.0%	0.0%																																					
	1,179,000	0.0%	0.0%																																					
	1,133,000	0.0%	0.0%																																					
< 1,000,000	2,927,000	0.0%	0.0%																																					
	800,000	0.0%	0.0%																																					
	800,000	0.0%	0.0%																																					
	451,000	0.0%	0.0%																																					
	448,000	0.0%	0.0%																																					
	200,000	0.0%	0.0%																																					
	124,000	0.0%	0.0%																																					
	75,000	0.0%	0.0%																																					
	25,000	0.0%	0.0%																																					
	4,000	0.0%	0.0%																																					
	-200,000	0.0%	0.0%																																					
Total Non-Firm Contract Purchases	11,502,405,880	46.5%	69.2%																																					
Total Firm & Non-Firm Contracts Purchases	18,010,075,785																																							
OTHER																																								
	-1,389,934,000	-5.6%	-8.4%																																					
	-2,877,267,000	-11.6%	-17.3%																																					
	448,599,000	1.8%	2.7%																																					
	-405,653,455	-1.6%	-2.4%																																					
	42,945,545																																							
Total "Other" Adjustments	-1,389,934,000																																							
Total Non-Firm Contract Purchases Less Other Adjustments (1),(2)	10,112,471,880	40.8%	60.8%	3,757,706	51	88	3,786,077																													100.00%	10,112,471,880	3,757,706	51	88
Total Firm & Non-Firm Contracts Purchases Less Other Adjustments	16,620,141,785	67.1%	100.0%																																					
Total Firm & Non-Firm Contracts Purchases & PSE Generated Less Other Adjustments	24,758,012,912																																							

Data Source:
[1] PSE 2012 Summary of Generation (PSE February 2013).
[2] PSE Colstrip Quarterly Report.

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 7-1. Total Emissions by Source

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Emission Source	Energy			Emissions								Emission Intensity			
	Amount	(UOM)	(%) (2)	CO_2		CH_4		N_2O		SF_6		CO_2 (UOM)	CH_4 (UOM)	N_2O (UOM)	SF_6 (UOM)
				(metric ton)	(%) (3)	(metric ton)	(%) (3)	(metric ton)	(%) (3)	(metric ton)	(%) (3)				
Generated and Purchased Electricity															
PSE-Owned Electric Operations															
Hydro	746,739,664	kWh	3.0%	0	0%	0	0%	0	0%	0	0%	0 lb/kWh	0 lb/kWh	0 lb/kWh	0 lb/kWh
Coal	3,809,524,012	kWh	15.4%	4,107,969	27.9%	402	13.5%	58	35.4%	0	0%	2.4 lb/kWh	2.3E-04 lb/kWh	3.4E-05 lb/kWh	0 lb/kWh
Natural Gas/ Oil	1,758,794,382	kWh	7.1%	1,328,010	9.0%	29	1.0%	3.6	2.2%	0	0%	1.7 lb/kWh	3.6E-05 lb/kWh	4.5E-06 lb/kWh	0 lb/kWh
Wind	1,822,813,069	kWh	7.4%	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%	-0.005	100%	NC	NC	NC	NC
Total - PSE-owned Electric Operations	**8,137,871,127**	**kWh**	**32.9%**	**5,435,979**	**36.9%**	**430**	**14.5%**	**62**	**37.5%**	**-0.005**	**100%**	**1.5 lb/kWh**	**1.2E-04 lb/kWh**	**1.7E-05 lb/kWh**	**0 lb/kWh**
Firm & Non-Firm Contracts Purchases															
Firm Contracts	6,507,669,905	kWh	26.3%	723,532	4.9%	16	0.5%	15	9.2%	0	0%	0.2 lb/kWh	5.3E-06 lb/kWh	5.1E-06 lb/kWh	0 lb/kWh
Non-Firm Contracts (1)	10,112,471,880	kWh	40.8%	3,757,706	25.5%	51	1.7%	88	53.3%	0	0%	0.8 lb/kWh	1.1E-05 lb/kWh	1.9E-05 lb/kWh	0 lb/kWh
Total - Firm & Non-Firm Contracts Purchases	**16,620,141,785**	**kWh**	**67.1%**	**4,481,237**	**30.4%**	**67**	**2.2%**	**103**	**62.5%**	**0**	**0%**	**0.6 lb/kWh**	**8.8E-06 lb/kWh**	**1.4E-05 lb/kWh**	**0 lb/kWh**
Total - Generated and Purchased Electricity	**24,758,012,912**	**kWh**	**100%**	**9,917,217**	**67.3%**	**497**	**16.8%**	**165**	**100%**	**-0.005**	**100%**	**0.9 lb/kWh**	**4.4E-05 lb/kWh**	**1.5E-05 lb/kWh**	**0 lb/kWh**
Natural Gas Operations															
Distribution and Storage of PSE-owned Natural Gas Operations															
Distribution	903,534,000	thm	100%	76	0%	2,469	83.2%	0	0%	0	0%	1.9E-04 lb/thm	0.01 lb/thm	0 lb/thm	0 lb/thm
Total - Natural Gas Operations	**903,534,000**	**thm**	**100%**	**76**	**0%**	**2,469**	**83.2%**	**0**	**0%**	**0**	**0%**	**1.9E-04 lb/thm**	**0.01 lb/thm**	**0 lb/thm**	**0 lb/thm**
Natural Gas Supply															
Supply to End-Users	875,121,331	thm	100%	4,813,167	32.7%	0	0%	0	0%	0	0%	12 lb/thm	0 lb/thm	0 lb/thm	0 lb/thm
Total - Natural Gas Supply	**875,121,331**	**thm**	**100%**	**4,813,167**	**32.7%**	**0**	**0%**	**0**	**0%**	**0**	**0%**	**12 lb/thm**	**0 lb/thm**	**0 lb/thm**	**0 lb/thm**
Emissions from All Sources				**14,730,460**	**100%**	**2,965**	**100%**	**165**	**100%**	**-0.005**	**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 - 2012 Greenhouse Gas Inventory

Emission Source	Energy			Emissions in CO_2 Equivalents (CO_2e) - 100-Year Timeframe (Tons)										Emission Intensity	
	Amount	(UOM)	(%) (2)	**CO_2**		**CH_4**		**N_2O**		**SF_6**		**Total**		**Total**	(UOM)
				(metric ton)	(%) (3)	(metric ton)	(%) (3)	(metric ton)	(%) (3)	(metric ton)	(%) (3)	(metric ton)	(%) (3)		
Generated and Purchased Electricity															
PSE-Owned Electric Operations															
Hydro	746,739,664	kWh	3.0%	0	0%	0	0%	0	0%	0	0%	0	0%	0	lb/kWh
Coal	3,809,524,012	kWh	15.4%	4,107,969	27.7%	8,436	0.1%	18,114	0.1%	0	0%	4,134,519	27.9%	2.4	lb/kWh
Natural Gas/ Oil	1,758,794,382	kWh	7.1%	1,328,010	8.9%	599	0.004%	1,105	0.01%	0	0%	1,329,713	9.0%	1.7	lb/kWh
Wind	1,822,813,069	kWh	7.4%	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%	-108	-0.001%	-108	-0.001%	NC	
Total - PSE-owned Electric Operations	**8,137,871,127**	**kWh**	**32.9%**	**5,435,979**	**36.6%**	**9,035**	**0.1%**	**19,219**	**0.1%**	**-108**	**-0.001%**	**5,464,124**	**36.8%**	**1.5**	**lb/kWh**
Firm & Non-Firm Contracts Purchases															
Firm Contracts	6,507,669,905	kWh	26.3%	723,532	4.9%	328	0.002%	4,699	0.03%	0	0%	728,558	4.9%	0.2	lb/kWh
Non-Firm Contracts (1)	10,112,471,880	kWh	40.8%	3,757,706	25.3%	1,069	0.01%	27,302	0.2%	0	0%	3,786,077	25.5%	0.8	lb/kWh
Total - Firm & Non-Firm ContractsPurchases	**16,620,141,785**	**kWh**	**67.1%**	**4,481,237**	**30.2%**	**1,397**	**0.0%**	**32,001**	**0.2%**	**0**	**0%**	**4,514,635**	**30.4%**	**0.6**	**lb/kWh**
Total - Generated and Purchased Electricity	**24,758,012,912**	**kWh**	**100%**	**9,917,217**	**66.8%**	**10,432**	**0.1%**	**51,220**	**0.3%**	**-108**	**-0.001%**	**9,978,760**	**67.2%**	**0.9**	**lb/kWh**
Natural Gas Operations															
Distribution and Storage of PSE-owned Natural Gas Operations															
Distribution	903,534,000	thm	100%	76	0.001%	51,840	0.3%	0	0%	0	0%	51,917	0.3%	0.1	lb/thm
Total - Natural Gas Operations	**903,534,000**	**thm**	**100%**	**76**	**0.001%**	**51,840**	**0.3%**	**0**	**0%**	**0**	**0%**	**51,917**	**0.3%**	**0.1**	**lb/thm**
Natural Gas Supply															
Supply to End-Users	875,121,331	thm	100%	4,813,167	32.4%	0	0%	0	0%	0	0%	4,813,167	32.4%	12	lb/thm
Total - Natural Gas Supply	**875,121,331**	**thm**	**100%**	**4,813,167**	**32.4%**	**0**	**0%**	**0**	**0%**	**0**	**0%**	**4,813,167**	**32.4%**	**12**	**lb/thm**
Emissions from All Sources				**14,730,460**	**99.2%**	**62,272**	**0.4%**	**51,220**	**0.3%**	**-108**	**-0.001%**	**14,843,844**	**100%**	**NC**	

Data Source:

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

Global Warming Potentials [1]**:**

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

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 CO_2e among all sources.

(4) NC = Not calculated.

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

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Emission Source	2012					2011					2010					2009					2008				
	Energy Amount (kWh)	(%) (4)	Emissions CO$_2$e (metric ton)	(%) (5)	Emission Intensity (lb/kWh)	Energy Amount (kWh)	(%) (4)	Emissions CO$_2$e (metric ton)	(%) (5)	Emission Intensity (lb/kWh)	Energy Amount (kWh)	(%) (4)	Emissions CO$_2$e (metric ton)	(%) (5)	Emission Intensity (lb/kWh)	Energy Amount (kWh)	(%) (4)	Emissions CO$_2$e (metric ton)	(%) (5)	Emission Intensity (lb/kWh)	Energy Amount (kWh)	(%) (4)	Emissions CO$_2$e (metric ton)	(%) (5)	Emission Intensity (lb/kWh)
Generated and Purchased Electricity																									
PSE-Owned Electric Operations																									
Hydro	746,739,664	3%	0	0%	0	683,977,604	3%	0	0%	0	929,596,698	4%	0	0%	0	987,779,034	4%	0	0%	0	974,924,000	4%	0	0%	0
Coal	3,809,524,012	15%	4,134,519	41%	2.39	4,556,429,000	17%	4,533,837	43%	2.19	5,650,381,500	22%	5,570,038	47%	2.17	4,788,435,750	17%	4,807,121	41%	2.21	5,516,688,000	22%	5,599,953	50%	2.24
Natural Gas/ Oil	1,758,794,382	7%	1,329,713	13%	1.67	1,243,003,923	5%	801,936	8%	1.42	2,754,472,071	11%	1,624,325	14%	1.30	4,363,146,050	16%	1,754,550	15%	0.89	2,269,586,297	9%	836,555	8%	0.81
Wind	1,822,813,069	7%	0	0%	0	1,163,877,414	4%	0	0%	0	990,925,943	4%	0	0%	0	946,494,138	3%	0	0%	0	1,106,780,000	4%	0	0%	0
Electrical Transmission and Distribution Equipment	0	0%	-108	-0.001%	NC	0	0%	0	0%	NC	0	0%	NC	NC	NC	0	0%	NC	NC	NC	0	0%	44,005	0.4%	NC
Total - PSE-owned Electric Operations	**8,137,871,127**	**33%**	**5,464,124**	**55%**	**1.48**	**7,647,287,941**	**29%**	**5,335,773**	**51%**	**1.54**	**10,325,376,212**	**41%**	**7,194,362**	**60%**	**1.54**	**11,085,854,972**	**40%**	**6,561,671**	**56%**	**1.30**	**9,867,978,297**	**39%**	**6,480,513**	**58%**	**1.45**
Firm & Non-Firm Contracts Purchases																									
Firm Contracts	5,929,503,545	24%	478,431	5%	0.18	7,515,378,308	28%	458,542	4%	0.13	6,894,780,000	27%	1,168,441	10%	0.37	6,138,673,570	22%	599,766	5%	0.22	6,918,194,390	27%	792,837	7%	0.25
PURPA Purchases	557,023,943	2%	224,302	2%	0.89	1,480,982,082	6%	755,588	7%	1.12	2,036,029,490	8%	1,099,738	9%	1.19	2,140,182,620	8%	1,176,671	10%	1.21	1,790,648,482	7%	965,807	9%	1.19
Non-Firm Contracts [1]	10,112,471,880	41%	3,786,077	38%	0.83	9,858,682,280	37%	3,868,055	37%	0.86	6,226,857,600	24%	2,443,108	21%	0.86	8,106,128,920	30%	3,340,203	29%	0.91	6,969,392,040	27%	2,871,800	26%	0.91
Biomass	21,142,417	0.09%	25,825	0.3%	2.69	16,299,811	0.06%	13,938	0.1%	1.89	11,149,693	0.04%	9,534	0.08%	1.89	6,904,930	0.03%	9,059	0.08%	2.89	2,232,000	0.01%	2,928	0.03%	2.89
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	**16,620,141,785**	**67%**	**4,514,635**	**45%**	**0.60**	**18,871,342,481**	**71%**	**5,096,123**	**49%**	**0.60**	**15,168,816,783**	**59%**	**4,720,822**	**40%**	**0.69**	**16,391,890,040**	**60%**	**5,125,700**	**44%**	**0.69**	**15,680,466,912**	**61%**	**4,633,373**	**42%**	**0.65**
Total - Generated and Purchased Electricity	**24,758,012,912**	**100%**	**9,978,760**	**100%**	**0.89**	**26,518,630,422**	**100%**	**10,431,896**	**100%**	**0.87**	**25,494,192,995**	**100%**	**11,915,185**	**100%**	**1.03**	**27,477,745,012**	**100%**	**11,687,371**	**100%**	**0.94**	**25,548,445,209**	**100%**	**11,113,886**	**100%**	**0.96**

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 CO$_2$ 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 - 2002 through 2012

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Emission Source	2012					2011				
	Energy Amount		Emissions CO$_2$		Emission Intensity	Energy Amount		Emissions CO$_2$		Emission Intensity
	(kWh)	(%) (4)	(metric ton)	(%) (5)	(lb/kWh)	(kWh)	(%) (4)	(metric ton)	(%) (5)	(lb/kWh)
Generated and Purchased Electricity										
PSE-Owned Electric Operations										
Hydro	746,739,664	3%	0	0%	0	683,977,604	3%	0	0%	0
Coal	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	1,758,794,382	7%	1,328,010	13%	1.66	1,243,003,923	5%	801,158	8%	1.42
Wind	1,822,813,069	7%	0	0%	0	1,163,877,414	4%	0	0%	0
Electrical Transmission and Distribution Equipment	0	0%	0	0.000%	NC	0	0%	0	0%	NC
Total - PSE-owned Electric Operations	**8,137,871,127**	**33%**	**5,435,979**	**55%**	**1.47**	**7,647,287,941**	**29%**	**5,300,614**	**51%**	**1.53**
Firm & Non-Firm Contracts Purchases										
Firm Contracts	5,929,503,545	24%	474,849	5%	0.18	7,515,378,308	28%	455,265	4%	0.13
PURPA Purchases	557,023,943	2%	223,437	2%	0.88	1,480,982,082	6%	752,433	7%	1.12
Non-Firm Contracts [1]	10,112,471,880	41%	3,757,706	38%	0.82	9,858,682,280	37%	3,840,396	37%	0.86
Biomass	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 -				
Total - Firm & Non-Firm Contracts Purchases	**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	**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				
	Energy Amount		Emissions CO$_2$		Emission Intensity	Energy Amount		Emissions CO$_2$		Emission Intensity
	(kWh)	(%) (4)	(metric ton)	(%) (5)	(lb/kWh)	(kWh)	(%) (4)	(metric ton)	(%) (5)	(lb/kWh)
Generated and Purchased Electricity										
PSE-Owned Electric Operations										
Hydro	929,596,698	4%	0	0%	0	987,779,034	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
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
Wind	990,925,943	4%	0	0%	0	946,494,138	3%	0	0%	0
Electrical Transmission and Distribution Equipment	0	0%	NC	NC	NC	0	0%	0	0%	0
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**
Firm & Non-Firm Contracts Purchases										
Firm Contracts	6,894,780,000	27%	1,162,048	10%	0.37	6,138,673,570	22%	596,901	5%	0.21
PURPA Purchases	2,036,029,490	8%	1,095,233	9%	1.19	2,140,182,620	8%	1,171,620	10%	1.21
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
Biomass	11,149,693	0.04%	9,321	0.08%	1.84	6,904,930	0.03%	8,856	0.08%	2.83
Interchange/ Optimization In	- 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**
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**

Emission Source	2008					2007				
	Energy Amount		Emissions CO$_2$		Emission Intensity	Energy Amount		Emissions CO$_2$		Emission Intensity
	(kWh)	(%) (4)	(metric ton)	(%) (5)	(lb/kWh)	(kWh)	(%) (4)	(metric ton)	(%) (5)	(lb/kWh)
Generated and Purchased Electricity										
PSE-Owned Electric Operations										
Hydro	974,924,000	4%	0	0%	0	1,154,233,830	5%	0	0%	0
Coal	5,516,688,000	22%	5,561,734	51%	2.22	5,142,912,000	20%	5,742,218	49%	2.46
Natural Gas/ Oil	2,269,586,297	9%	828,271	8%	0.80	1,310,625,020	5%	507,775	4%	0.85
Wind	1,106,780,000	4%	0	0%	0	1,015,323,546	4%	0	0%	0
Electrical Transmission and Distribution Equipment	0	0%	0	0%	0	- not presented in previous report -				
Total - PSE-owned Electric Operations	**9,867,978,297**	**39%**	**6,390,005**	**58%**	**1.43**	**8,623,094,396**	**34%**	**6,249,992**	**53%**	**1.60**
Firm & Non-Firm Contracts Purchases										
Firm Contracts	6,918,194,390	27%	789,075	7%	0.25	7,058,967,440	28%	739,219	6%	0.23
PURPA Purchases	1,790,648,482	7%	961,638	9%	1.18	2,285,841,710	9%	1,256,965	11%	1.21
Non-Firm Contracts [1]	6,969,392,040	27%	2,852,247	26%	0.90	7,384,691,000	29%	3,439,577	29%	1.03
Biomass	2,232,000	0.01%	2,863	0.03%	2.83	2,091,600	0.01%	2,683	0.02%	2.83
Interchange/ Optimization In	- not accounted for separately -					- not accounted for separately -				
Total - Firm & Non-Firm Contracts Purchases	**15,680,466,912**	**61%**	**4,605,823**	**42%**	**0.65**	**16,731,591,750**	**66%**	**5,438,444**	**47%**	**0.72**
Total - Generated and Purchased Electricity	**25,548,445,209**	**100%**	**10,995,828**	**100%**	**0.95**	**25,354,686,146**	**100%**	**11,688,436**	**100%**	**1.02**

Emission Source	2006					2005				
	Energy Amount		Emissions CO$_2$		Emission Intensity	Energy Amount		Emissions CO$_2$		Emission Intensity
	(kWh)	(%) (4)	(metric ton)	(%) (5)	(lb/kWh)	(kWh)	(%) (4)	(metric ton)	(%) (5)	(lb/kWh)
Generated and Purchased Electricity										
PSE-Owned Electric Operations										
Hydro	949,276,360	4%	0	0%	0	879,492,550	4%	0	0%	0
Coal	4,800,028,000	19%	5,368,465	44%	2.47	5,641,851,000	24%	5,641,982	48%	2.20
Natural Gas/ Oil	723,190,270	3%	307,204	3%	0.94	813,077,310	3%	323,376	3%	0.88
Wind	372,828,350	1%	0	0%	0	33,670,170	0%	0	0%	0
Total - PSE-owned Electric Operations	**6,845,322,980**	**27%**	**5,675,669**	**46%**	**1.83**	**7,368,091,030**	**31%**	**5,965,358**	**51%**	**1.78**
Firm & Non-Firm Contracts Purchases										
Firm Contracts	6,926,996,520	28%	724,305	6%	0.23	6,759,676,680	29%	801,272	7%	0.26
PURPA Purchases	2,689,484,164	11%	1,517,860	12%	1.24	2,838,412,832	12%	1,620,792	14%	1.26
Non-Firm Contracts [1]	8,569,778,912	34%	4,353,649	35%	1.12	6,701,277,420	28%	3,404,406	29%	1.12
Biomass	1,823,280	0.01%	726	0.01%	0.88	1,790,160	0.01%	713	0.01%	0.88
Interchange/ Optimization In	- not accounted for separately -					- not accounted for separately -				
Total - Firm & Non-Firm Contracts Purchases	**18,188,082,876**	**73%**	**6,596,539**	**54%**	**0.80**	**16,301,157,092**	**69%**	**5,827,183**	**49%**	**0.79**
Total - Generated and Purchased Electricity	**25,033,405,856**	**100%**	**12,272,208**	**100%**	**1.08**	**23,669,248,122**	**100%**	**11,792,540**	**100%**	**1.10**

Emission Source	2004					2003				
	Energy Amount		Emissions CO$_2$		Emission Intensity	Energy Amount		Emissions CO$_2$		Emission Intensity
	(kWh)	(%) (4)	(metric ton)	(%) (5)	(lb/kWh)	(kWh)	(%) (4)	(metric ton)	(%) (5)	(lb/kWh)
Generated and Purchased Electricity										
PSE-Owned Electric Operations										
Hydro	1,130,179,590	5%	0	0%	0	1,238,899,970	5%	0	0%	0
Coal	5,119,002,000	21%	5,388,530	47%	2.32	4,950,734,000	19%	5,263,747	39%	2.34
Natural Gas/ Oil	799,087,351	3%	343,066	3%	0.95	776,204,970	3%	351,156	3%	1.00
Wind	0	0%	0	0%	NC	0	0%	0	0%	NC
Total - PSE-owned Electric Operations	**7,048,268,941**	**29%**	**5,731,596**	**50%**	**1.79**	**6,965,838,940**	**27%**	**5,614,903**	**42%**	**1.78**
Firm & Non-Firm Contracts Purchases										
Firm Contracts	6,499,007,477	27%	735,877	6%	0.25	7,361,072,125	28%	1,512,661	11%	0.45
PURPA Purchases	2,922,337,463	12%	1,664,165	15%	1.26	3,653,398,581	14%	2,189,100	16%	1.32
Non-Firm Contracts [1]	7,528,342,413	31%	3,298,121	29%	0.97	8,082,457,480	31%	4,030,237	30%	1.10
Biomass	33,116,580	0.14%	13,181	0.12%	0.88	- not accounted for separately -				
Interchange/ Optimization In	- not accounted for separately -					45,552,411	0.2%	27,687	0.2%	1.34
Total - Firm & Non-Firm Contracts Purchases	**16,982,803,933**	**71%**	**5,711,344**	**50%**	**0.74**	**19,142,480,597**	**73%**	**7,759,685**	**58%**	**0.89**
Total - Generated and Purchased Electricity	**24,031,072,874**	**100%**	**11,442,939**	**100%**	**1.05**	**26,108,319,537**	**100%**	**13,374,589**	**100%**	**1.13**

Emission Source	2002				
	Energy Amount		Emissions CO$_2$		Emission Intensity
	(kWh)	(%) (4)	(metric ton)	(%) (5)	(lb/kWh)
Generated and Purchased Electricity					
PSE-Owned Electric Operations					
Hydro	1,351,540,000	5%	0	0%	0
Coal	4,627,901,000	17%	4,930,717	40%	2.35
Natural Gas/ Oil	1,016,835,000	4%	438,754	4%	0.95
Wind	0	0%	0	0%	NC
Total - PSE-owned Electric Operations	**6,996,276,000**	**26%**	**5,369,472**	**43%**	**1.69**
Firm & Non-Firm Contracts Purchases					
Firm Contracts	12,085,729,000	45%	2,438,626	20%	0.44
PURPA Purchases	- included in firm contracts purchases -				
Non-Firm Contracts [1]	7,584,398,000	28%	4,609,902	37%	1.34
Biomass	- not accounted for separately -				
Interchange/ Optimization In	- not accounted for separately -				
Total - Firm & Non-Firm Contracts Purchases	**19,670,127,000**	**74%**	**7,048,528**	**57%**	**0.79**
Total - Generated and Purchased Electricity	**26,666,403,000**	**100%**	**12,418,000**	**100%**	**1.03**

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 CO$_2$ 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) - 2011 vs. 2012

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Emission Source	2011 vs. 2012					2012					2011				
	Energy Amount		Emissions CO$_2$e		Emission Intensity	Energy Amount		Emissions CO$_2$e		Emission Intensity	Energy Amount		Emissions CO$_2$e		Emission Intensity
	(kWh)	(%) (3)	(metric ton)	(%) (4)	(lb/kWh)	(kWh)	(%) (3)	(metric ton)	(%) (4)	(lb/kWh)	(kWh)	(%) (3)	(metric ton)	(%) (4)	(lb/kWh)
Generated and Purchased Electricity															
PSE-Owned Electric Operations															
Hydro	62,762,060	9%	0	NA	0	746,739,664	3%	0	0%	0	683,977,604	3%	0	0%	0
Coal	-746,904,988	-16%	-399,318	-9%	0.20	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	515,790,459	41%	527,777	66%	0.24	1,758,794,382	7%	1,329,713	13%	1.67	1,243,003,923	5%	801,936	8%	1.42
Wind	658,935,655	57%	0	NA	0	1,822,813,069	7%	0	0%	0	1,163,877,414	4%	0	0%	0
Electrical Transmission and Distribution Equipment	0	NA	-108	NA	NC	0	0%	-108	-0.001%	NC	0	0%	0	0%	NC
Total - PSE-owned Electric Operations	**490,583,186**	**6%**	**128,351**	**2.4%**	**-0.06**	**8,137,871,127**	**33%**	**5,464,124**	**55%**	**1.48**	**7,647,287,941**	**29%**	**5,335,773**	**51%**	**1.54**
Firm & Non-Firm Contracts Purchases															
Firm Contracts	-1,585,874,763	-21%	19,889	4%	0.04	5,929,503,545	24%	478,431	5%	0.18	7,515,378,308	28%	458,542	4%	0.13
PURPA Purchases	-923,958,139	-62%	-531,285	-70%	-0.24	557,023,943	2%	224,302	2%	0.89	1,480,982,082	6%	755,588	7%	1.12
Non-Firm Contracts [1]	253,789,600	3%	-81,979	-2%	-0.04	10,112,471,880	41%	3,786,077	38%	0.83	9,858,682,280	37%	3,868,055	37%	0.86
Biomass	4,842,606	30%	11,887	85%	0.81	21,142,417	0.09%	25,825	0.26%	2.69	16,299,811	0.06%	13,938	0.13%	1.89
Interchange/ Optimization In	- not accounted for separately -					- not accounted for separately -					- not accounted for separately -				
Total - Firm & Non-Firm Contracts Purchases	**-2,251,200,696**	**-12%**	**-581,488**	**-11%**	**0.004**	**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	**-1,760,617,510**	**-7%**	**-453,137**	**-4%**	**0.02**	**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 CO$_2$ 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 - 2012 Greenhouse Gas Inventory

1. Electric Demand-Side Reduction

Annual Conservation: 339,500,000 kWh [3]

Source of Emissions Savings	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)
Electricity	**115,829**	**0.28**	**0.23**

Emission Factors

Fuel Type	CO_2 (lb/kWh)	CH_4 (lb/kWh)	N_2O (lb/kWh)
Natural Gas CCGT (1)	0.752 [1]	1.85E-06 [2]	1.50E-06 [2]

2. Natural Gas Conservation Programs

Annual Conservation: 5,205,000 thm [3]

Natural Gas Emissions: 18,218 thm
1,770,408 ft^3

Methane Emissions: 32.3 metric ton

Source of Emissions Savings	CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)
Natural Gas	**0**	**32.33**	**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 2011 in Washington	1,029	Btu/ft3	[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_2O (metric ton)
Electricity and Natural Gas	**115,829**	**32.61**	**0.23**

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 (DOE/EIA April 2002).
[3] PSE 2012 Energy Efficiency Services Program Results, Table 1a (PSE 2013).
[4] Methane Emissions from the Natural Gas Industry, Volume 2: Technical Report, Table 4-3 (EPA/GRI June 1996).
[5] Natural Gas Annual 2011, Table 16 (DOE/EIA February 2013).

Note(s):

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

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

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Unit ID	Unit Type [1]	Capacity [1] (MW)	PSE Share [1]	Fuel Type [2]	Fuel Usage [2]	(UOM)	HHV (1)	(UOM)	HI (2), [3]	(UOM)	PSE Portion of Emissions (4) CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)
Colstrip Unit 1	Coal	307	50%	Coal LPG	821,628 444,759	short ton (3) gal (3)	17.18	MMBtu/ton (3)	12,802,380	MMBtu	737,857 {1}	70.41 {2}	10.24 {2}
Colstrip Unit 2	Coal			Coal LPG	854,226 330,161	short ton (3) gal (3)	17.18	MMBtu/ton (3)	13,310,313	MMBtu	780,290 {1}	73.21 {2}	10.65 {2}
Colstrip Unit 3	Coal	370	25%	Coal Distillate Fuel Oil	2,936,981 312,400	short ton (3) gal (3)	16.99	MMBtu/ton (3)	45,267,653	MMBtu	1,261,919 {1}	124.49 {2}	18.11 {2}
Colstrip Unit 4	Coal			Coal Distillate Fuel Oil	3,152,283 121,047	short ton (3) gal (3)	16.99	MMBtu/ton (3)	48,586,101	MMBtu	1,327,904 {1}	133.61 {2}	19.43 {2}
									Total		**4,107,969**	**402**	**58**

Emission Factors:

Fuel Type	CH_4 (kg/MMBtu)	N_2O (kg/MMBtu)
Coal	1.1E-02 [4]	1.6E-03 [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] PSE 2012 Form 10-K (PSE, 2012).
[2] 2012 PSE Colstrip Emission Inventory Data Report.
[3] ECMPS Feedback (EPA).
[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) 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-2. Emissions from PSE-Owned Electric Operations: Natural Gas/ Petroleum

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Unit ID	Unit Type [1]	Capacity [1] (MW)	PSE Share [1]	Fuel Type [2]	Fuel Usage (UOM) [2]	HHV (UOM) (1)	HI (UOM) (2), [3]	PSE Share of Emissions (4)		
								CO_2 (metric ton)	CH_4 (metric ton)	N_2O (metric ton)
Crystal Mountain	Internal Combustion	3	100%	Distillate Fuel Oil No. 2	23,067 gal	137,030 Btu/gal	NR (3)	9,818.80 {3}	0.40 {5}	0.080 {5}
Encogen 1	Natural gas cogeneration	165	100%	Natural Gas Distillate Fuel Oil No. 2	344,036 kscf (3) 7,947 gal	NR (3)	337,716 MMBtu	18,220.53 {1}	0.34 {2}	0.03 {2}
Encogen 2	Natural gas cogeneration			Natural Gas Distillate Fuel Oil No. 2	318,784 kscf (3) 4,001 gal	NR (3)	311,895 MMBtu	16,825.47 {1}	0.31 {2}	0.03 {2}
Encogen 3	Natural gas cogeneration			Natural Gas Distillate Fuel Oil No. 2	316,339 kscf (3) 6,045 gal	NR (3)	307,227 MMBtu	16,580.17 {1}	0.31 {2}	0.03 {2}
Ferndale 1	Natural gas combined cycle	253	100%	Natural Gas	8,692 kscf (3)	NR (3)	130,809 MMBtu	7,051.96 {1}	0.13 {2}	0.01 {2}
Ferndale 2	Natural gas combined cycle			Natural Gas	8,692 kscf (3)	NR (3)	134,617 MMBtu	7,258.08 {1}	0.13 {2}	0.01 {2}
Frederickson 1	Natural gas combined cycle	136	49.85%	Natural Gas	1,218,529 kscf (3)	NR (3)	2,578,142 MMBtu	138,996.94 {1}	2.58 {2}	0.26 {2}
Fredonia 1	Dual-fuel combustion turbines	207	100%	Natural Gas Distillate Fuel Oil No. 2	140,805 kscf 77,511 gal	1025.0 Btu/scf 139,759 Btu/gal	NR (3) NR (3)	7,652.12 {3} 33,650.33 {3}	0.14 {5} 1.36 {5}	0.01 {5} 0.273 {5}
								41,302.45	1.51	0.29
Fredonia 2	Dual-fuel combustion turbines			Natural Gas Distillate Fuel Oil No. 2	68,472 kscf 159,829 gal	1025.0 Btu/scf 139,759 Btu/gal	NR (3) NR (3)	3,721.15 {3} 69,387.55 {3}	0.07 {5} 2.81 {5}	0.01 {5} 0.563 {5}
								73,108.70	2.88	0.57
Fredonia 3	Dual-fuel combustion turbines	107	100%	Natural Gas Distillate Fuel Oil No. 2	109,319 kscf (3) 38,488 gal	NR (3)	117,098 MMBtu	6,418.30 {1}	0.12 {2}	0.01 {2}
Fredonia 4	Dual-fuel combustion turbines			Natural Gas Distillate Fuel Oil No. 2	141,040 kscf (3) 28,308 gal	NR (3)	149,833 MMBtu	8,154.64 {1}	0.15 {2}	0.01 {2}
Frederickson 1	Dual-fuel combustion turbines	149	100%	Natural Gas Distillate Fuel Oil No. 2	269,030 kscf 20,488 gal	1025.0 Btu/scf 138,812 Btu/gal	NR (3) NR (3)	14,620.57 {3} 8,834.31 {3}	0.28 {5} 0.36 {5}	0.03 {5} 0.072 {5}
								23,454.88	0.63	0.10
Frederickson 2	Dual-fuel combustion turbines			Natural Gas Distillate Fuel Oil No. 2	286,398 kscf 9,210 gal	1025.0 Btu/scf 138,812 Btu/gal	NR (3) NR (3)	15,564.44 {3} 3,971.30 {3}	0.29 {5} 0.16 {5}	0.03 {5} 0.032 {5}
								19,535.74	0.45	0.06
Goldendale	Natural gas combined cycle	278	100%	Natural Gas	6,364,557 kscf (3)	NR (3)	6,034,718 MMBtu	325,354.94 {1}	6.03 {2}	0.60 {2}
Mint Farm	Natural gas combined cycle	297	100%	Natural Gas	7,787,711 kscf (3)	NR (3)	8,039,461 MMBtu	433,428.11 {1}	8.04 {2}	0.80 {2}
Sumas	Natural gas cogeneration	127	100%	Natural Gas	1,841,152 kscf (3)	NR (3)	1,976,052 MMBtu	106,537.22 {1}	1.98 {2}	0.20 {2}
Whitehorn 2	Dual-fuel combustion turbines	149	100%	Natural Gas Distillate Fuel Oil No. 2	254,167 kscf 49,559 gal	1025.0 Btu/scf 140,760 Btu/gal	NR (3) NR (3)	13,812.83 {3} 21,669.45 {3}	0.26 {5} 0.88 {5}	0.03 {5} 0.176 {5}
								35,482.29	1.14	0.20
Whitehorn 3	Dual-fuel combustion turbines			Natural Gas Distillate Fuel Oil No. 2	222,611 kscf 64,912 gal	1025.0 Btu/scf 140,760 Btu/gal	NR (3) NR (3)	12,097.92 {3} 28,382.49 {3}	0.23 {5} 1.15 {5}	0.02 {5} 0.230 {5}
								40,480.41	1.38	0.25
							Total	**1,328,010**	**29**	**4**

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

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Emission Factors:

Fuel Type	CO_2 (kg/MMBtu)	CH_4 (kg/MMBtu)	N_2O (kg/MMBtu)
Natural Gas	53.02 [4]	1.0E-03 [4]	1.0E-04 [4]
Distillate Fuel Oil No. 2	73.96 [4]	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).
{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] PSE.
[2] PSE.
[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.
(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 - 2012 Greenhouse Gas Inventory

Fuel Type	Heat Rate [8]	Emission Rate			Emission Rate (6)		
		CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
	(Btu/kWh)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/kWh)	(lb/kWh)	(lb/kWh)
Coal (1)	**8,800**				**2.095** [5]	**1.241E-05** [7]	**2.869E-05** [7]
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]	**3.816E-05** [7]	**1.388E-05** [7]
Nat Gas		116.98 [1]	0.000287 [2]	0.000233 [2]			
SCGT	10,745	116.98 [1]	0.000287 [2]	0.000233 [2]	1.257 [7]	3.084E-06 [7]	2.504E-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	10,745	110 [3]	0.0086 [3]	0.003 [3]	1.182 [7]	9.241E-05 [7]	3.224E-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)	**10,745**	**161.27** [1]	**0.00163** [2]	**0.0014** [2]	**1.969** [5]	**1.751E-05** [2]	**1.504E-05** [2]
Other					**0.819** [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 2009).
[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 Version 1.0 (EPA April 2012).
[7] Calculated values.
[8] PSE Integrated Resource Plan (Draft), Appendix D Figure D-13 (April 2013).

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 - 2012 Greenhouse Gas Inventory

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

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

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

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

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

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

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).

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

Puget Sound Energy - 2012 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, 2012.
98.3(c)(3)	Date of submittal.	By September 30, 2013.
98.3(c)(4)	For facilities, except as otherwise provided in paragraph (c)(12) of this section, report annual emissions of CO_2, CH_4, N_2O, each fluorinated GHG (as defined in §98.6), and each fluorinated heat transfer fluid (as defined in § 98.98) as follows:	See response in the following subsections.
98.3(c)(4)(i)	Annual emissions (excluding biogenic CO_2) aggregated for all GHG from all applicable source categories, expressed in metric tons of CO_2e calculated using Equation A-1 of this subpart. For electronics manufacturing (as defined in § 98.90), starting in reporting year 2012 the CO_2e calculation must include each fluorinated heat transfer fluid (as defined in § 98.98) whether or not it is also a fluorinated GHG.	See Tables B-7 through B-10.
98.3(c)(4)(ii)	Annual emissions of biogenic CO_2 aggregated for all applicable source categories, expressed in metric tons.	NA - There was no source of biogenic CO_2 emissions.
98.3(c)(4)(iii)	Annual emissions from each applicable source category, expressed in metric tons of each applicable GHG listed in paragraphs (c)(4)(iii)(A) through (c)(4)(iii)(E) of this section.	See response in the following subsections.
98.3(c)(4)(iii)(A)	Biogenic CO_2.	NA - There was no source of biogenic CO_2 emissions.
98.3(c)(4)(iii)(B)	CO_2 (excluding biogenic CO_2).	See Tables B-7 through B-10.
98.3(c)(4)(iii)(C)	CH_4.	See Tables B-7 through B-10.
98.3(c)(4)(iii)(D)	N_2O.	See Tables B-7 through B-10.
98.3(c)(4)(iii)(E)	Each fluorinated GHG (including those not listed in Table A-1 of this subpart).	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. This requirement applies beginning in reporting year 2012.	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)	When applying paragraph (c)(4)(i) of this section to fluorinated GHGs and fluorinated heat transfer fluids, calculate and report CO_2e for only those fluorinated GHGs and fluorinated heat transfer fluids listed in Table A-1 of this subpart.	See Tables B-7 through B-10.
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.	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.	No response required.
98.3(c)(5)	For suppliers, report annual quantities of CO_2, CH_4, N_2O, and each fluorinated GHG (as defined in §98.6) that would be emitted from combustion or use of the products supplied, imported, and exported during the year. Calculate and report quantities at the following levels:	See response in the following subsections.
98.3(c)(5)(i)	Total quantity of GHG aggregated for all GHG from all applicable supply categories in Table A-5 of this subpart and expressed in metric tons of CO_2e calculated using Equation A-1 of this subpart. For fluorinated GHGs, calculate and report CO_2e for only those fluorinated GHGs listed in Table 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. For fluorinated GHG, report quantities of all fluorinated GHG, including those not listed in Table A-1 to this subpart.	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.	Puget Sound Energy, Inc. 10885 NE 4th Street, Suite 1200, Bellevue, Washington 98004-5591.

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

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
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.	Puget Energy, Inc. 10885 NE 4th Street, Suite 1200, Bellevue, Washington 98004-5591.
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.	NA - The reporting entity is owned by a single private United States company.
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 reporting entity is owned by a single private United States company.
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 reporting entity is owned by a single private United States 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 reporting entity is owned by a single private United States 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 reporting entity is owned by a single private United States company.
98.3(c)(12)	For the 2010 reporting year only, facilities that have "part 75 units" (i.e. units that are subject to subpart D of this part or units that use the methods in part 75 of this chapter to quantify CO_2 mass emissions in accordance with §98.33(a)(5)) must report annual GHG emissions either in full accordance with paragraphs (c)(4)(i) through (c)(4)(iii) of this section or in full accordance with paragraphs (c)(12)(i) through (c)(12)(iii) of this section. If the latter reporting option is chosen, you must report:	Annual GHG emissions are reported in accordance with paragraphs (c)(4)(i) through (c)(4)(iii) of this section.
98.3(c)(12)(i)	Annual emissions aggregated for all GHG from all applicable source categories, expressed in metric tons of CO_2e calculated using Equation A-1 of this subpart. You must include biogenic CO_2 emissions from part 75 units in these annual emissions, but exclude biogenic CO_2 emissions from any non-part 75 units and other source categories.	NA - Annual GHG emissions are reported in accordance with paragraphs (c)(4)(i) through (c)(4)(iii) of this section.
98.3(c)(12)(ii)	Annual emissions of biogenic CO_2,expressed in metric tons (excluding biogenic CO2 emissions from part 75 units), aggregated for all applicable source categories.	NA - Annual GHG emissions are reported in accordance with paragraphs (c)(4)(i) through (c)(4)(iii) of this section.
98.3(c)(12)(iii)	Annual emissions from each applicable source category, expressed in metric tons of each applicable GHG listed in paragraphs (c)(12)(iii)(A) through (c)(12)(iii)(E) of this section. (A) Biogenic CO_2(excluding biogenic CO_2 emissions from part 75 units). (B) CO_2. You must include biogenic CO_2 emissions from part 75 units in these totals and exclude biogenic CO_2 emissions from other non-part 75 units and other source categories. (C) CH_4. (D) N_2O. (E) Each fluorinated GHG (including those not listed in Table A-1 of this subpart).	NA - Annual GHG emissions are reported in accordance with paragraphs (c)(4)(i) through (c)(4)(iii) of this section.

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

Puget Sound Energy - 2012 Greenhouse Gas Inventory

Rule Reference	Rule Description	Response
98.32	You must report CO_2, CH_4, and N_2O mass emissions from each stationary fuel combustion unit, except as otherwise indicated in this subpart.	See response in 98.36(b).
98.36(a)	In addition to the facility-level information required under §98.3, the annual GHG emissions report shall contain the unit-level or process-level emissions data in paragraphs (b) through (d) of this section (as applicable) and the emissions verification data in paragraph (e) of this section.	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 for boilers and process heaters only and relevant units of measure for other combustion sources.	See Table B-7.
98.36(b)(4)	Each type of fuel combusted in the unit during the report year.	See Table B-7.
98.36(b)(5)	The methodology (i.e., tier) used to calculate the CO_2 emissions for each type of fuel combusted (i.e., Tier 1, 2, 3, or 4).	See Table B-7.
98.36(b)(6)	The methodology start date, for each fuel type.	See Table B-7.
98.36(b)(7)	The methodology end date, for each fuel type.	See Table B-7.
98.36(b)(8)	For a unit that uses Tiers 1, 2, or 3:	See response in the following subsections.
98.36(b)(8)(i)	The annual CO_2 mass emissions (including biogenic CO_2), and the annual CH_4, and N_2O mass emissions for each type of fuel combusted during the reporting year, expressed in metric tons of each gas and in metric tons of CO_2e; and	See Table B-7.
98.36(b)(8)(ii)	Metric tons of biogenic CO_2emissions (if applicable).	NA - There is no biogenic CO_2 emissions associated with the facility.
98.36(b)(9)	For a unit that uses Tier 4:	See response in the following subsections.
98.36(b)(9)(i)	If the total annual CO_2 mass emissions measured by the CEMS consists entirely of non-biogenic CO_2 (i.e., CO_2 from fossil fuel combustion plus, if applicable, CO_2 from sorbent and/or process CO_2), report the total annual CO_2 mass emissions, expressed in metric tons. You are not required to report the combustion CO_2 emissions by fuel type.	See Table B-7.
98.36(b)(9)(ii)	Report the total annual CO_2 mass emissions measured by the CEMS. If this total includes both biogenic and non-biogenic CO_2, separately report the annual non-biogenic CO_2 mass emissions and the annual CO_2 mass emissions from biomass combustion, each expressed in metric tons. You are not required to report the combustion CO_2 emissions by fuel type.	NA - There was no unit that burned both fossil fuels and biomass.
98.36(b)(9)(iii)	An estimate of the heat input from each type of fuel listed in Table C-2 of this subpart that was combusted in the unit during the report year, and the annual CH_4 and N_2O emissions for each of these fuels, expressed in metric tons of each gas and in metric tons of CO_2e.	See Table B-7.
98.36(b)(10)	Annual CO_2 emissions from sorbent (if calculated using Equation C-11 of this subpart), expressed in metric tons.	NA - There was no sorbent used.
98.36(c)	Reporting alternatives for units using the four Tiers . You may use any of the applicable reporting alternatives of this paragraph to simplify the unit-level reporting required under paragraph (b) of this section.	NA - Reporting alternatives were not used.
98.36(d)	Units subject to part 75 of this chapter.	See response in the following subsections.
98.36(d)(1)	For stationary combustion units that are subject to subpart D of this part, you shall report the following unit-level information:	See response in the following subsections.
98.36(d)(1)(i)	Unit or stack identification numbers. Use exact same unit, common stack, common pipe, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, CP001, etc.) that are reported under §75.64 of this chapter.	See Table B-7.
98.36(d)(1)(ii)	Annual CO_2 emissions at each monitored location, expressed in both short tons and metric tons. Separate reporting of biogenic CO_2 emissions under §98.3(c)(4)(ii) and §98.3(c)(4)(iii)(A) is optional only for the 2010 reporting year, as provided in §98.3(c)(12).	See Table B-7.
98.36(d)(1)(iii)	Annual CH_4 and N_2O emissions at each monitored location, for each fuel type listed in Table C-2 that was combusted during the year (except as otherwise provided in §98.33(c)(4)(ii)(B)), expressed in metric tons of CO_2e.	See Table B-7.
98.36(d)(1)(iv)	The total heat input from each fuel listed in Table C-2 that was combusted during the year (except as otherwise provided in §98.33(c)(4)(ii)(B)), expressed in mmBtu.	See Table B-7.
98.36(d)(1)(v)	Identification of the Part 75 methodology used to determine the CO_2 mass emissions.	See Table B-7.
98.36(d)(1)(vi)	Methodology start date.	See Table B-7.
98.36(d)(1)(vii)	Methodology end date.	See Table B-7.
98.36(d)(1)(viii)	Acid Rain Program indicator.	See Table B-7.
98.36(d)(1)(ix)	Annual CO_2 mass emissions from the combustion of biomass, expressed in metric tons of CO_2e, except where the reporting provisions of §§98.3(c)(12)(i) through (c)(12)(iii) are implemented for the 2010 reporting year.	See Table B-7.
98.36(d)(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.

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

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

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

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Rule Reference	Rule Description	Response
98.232(a)	You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraph (b) through (i) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraph (b) through (i) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.	See Table B-8.
98.232(b)	For offshore petroleum and natural gas production, report CO_2, CH_4,and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions.	NA - The facility does not belong to this industry segment.
98.232(c)	For an onshore petroleum and natural gas production facility, report CO_2, CH4, and N_2O emissions from only the following source types on a single well-pad or associated with a single well-pad:	NA - The facility does not belong to this industry segment.
98.232(d)	For onshore natural gas processing, report CO_2, CH_4, and N_2O emissions from the following sources:	NA - The facility does not belong to this industry segment.
98.232(e)	For onshore natural gas transmission compression, report CO_2, CH_4, and N_2O emissions from the following sources:	NA - The facility does not belong to this industry segment.
98.232(f)	For underground natural gas storage, report CO_2, CH_4, and N_2O emissions from the following sources:	NA - The facility does not belong to this industry segment.
98.232(g)	For LNG storage, report CO_2, CH_4, and N_2O emissions from the following sources:	NA - The facility does not belong to this industry segment.
98.232(h)	LNG import and export equipment, report CO_2, CH_4, and N_2O emissions from the following sources:	NA - The facility does not belong to this industry segment.
98.232(i)	For natural gas distribution, report CO_2, CH_4, and N_2O emissions from the following sources:	See response in the following subsections.
98.232(i)(1)	Meters, regulators, and associated equipment at above grade transmission-distribution transfer stations, including equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.	See Table B-8.
98.232(i)(2)	Equipment leaks from vaults at below grade transmission-distribution transfer stations.	See Table B-8.
98.232(i)(3)	Meters, regulators, and associated equipment at above grade metering-regulating station.	See Table B-8.
98.232(i)(4)	Equipment leaks from vaults at below grade metering-regulating stations.	See Table B-8.
98.232(i)(5)	Pipeline main equipment leaks.	See Table B-8.
98.232(i)(6)	Service line equipment leaks.	See Table B-8.
98.232(i)(7)	Report under subpart W of this part the emissions of CO_2, CH_4, and N_2O emissions from stationary fuel combustion sources following the methods in §98.233(z).	See Table B-8.
98.232(j)	[Reserved]	No response required.
98.232(k)	Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C except for facilities under onshore petroleum and natural gas production 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.	NA - No stationary fuel combustion sources under this subpart.
98.236(a)	Report annual emissions in metric tons of CO_2e for each GHG separately for each of the industry segments listed in paragraphs (a)(1) through (8) of this section.	See response in the following subsections.
98.236(a)(1)	Onshore petroleum and natural gas production.	NA - The facility does not belong to this industry segment.
98.236(a)(2)	Offshore petroleum and natural gas production.	NA - The facility does not belong to this industry segment.
98.236(a)(3)	Onshore natural gas processing.	NA - The facility does not belong to this industry segment.
98.236(a)(4)	Onshore natural gas transmission compression.	NA - The facility does not belong to this industry segment.
98.236(a)(5)	Underground natural gas storage.	NA - The facility does not belong to this industry segment.
98.236(a)(6)	LNG storage.	NA - The facility does not belong to this industry segment.
98.236(a)(7)	LNG import and export.	NA - The facility does not belong to this industry segment.
98.236(a)(8)	Natural gas distribution.	See Table B-8.
98.236(b)	For offshore petroleum and natural gas production, report emissions of CH_4, CO_2, and N_2O as applicable to the source type (in metric tons CO_2e per year at standard conditions) individually for all of the emissions source types listed in the most recent BOEMRE study.	NA - The facility does not belong to this industry segment.
98.236(c)	Report the information listed in this paragraph for each applicable source type in metric tons of CO_2e for each GHG. If a facility operates under more than one industry segment, each piece of equipment should be reported under the unit's respective majority use segment. When a source type listed under this paragraph routes gas to flare, separately report the emissions that were vented directly to the atmosphere without flaring, and the emissions that resulted from flaring the gas. Both the vented and flared emissions will be reported under the respective source type and not under the flare source type.	See response in the following subsections.
98.236(c)(1)	For natural gas pneumatic devices	NA - The facility does not have this source type.
98.236(c)(2)	For natural gas driven pneumatic pumps	NA - The facility does not have this source type.
98.236(c)(3)	For each acid gas removal unit	NA - The facility does not have this source type.
98.236(c)(4)	For dehydrators	NA - The facility does not have this source type.
98.236(c)(5)	For well venting for liquids unloading	NA - The facility does not have this source type.
98.236(c)(6)	For well completions and workovers	NA - The facility does not have this source type.
98.236(c)(7)	For blowdown vent stack emission source	NA - The facility does not have this source type.
98.236(c)(8)	For gas emitted from produced oil sent to atmospheric tanks	NA - The facility does not have this source type.
98.236(c)(9)	For transmission tank emissions identified in §98.233(k) from scrubber dump valves report the following:	NA - The facility does not have this source type.

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

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Rule Reference	Rule Description	Response
98.236(c)(10)	For well testing venting and flaring	NA - The facility does not have this source type.
98.236(c)(11)	For associated natural gas venting and flaring	NA - The facility does not have this source type.
98.236(c)(12)	For flare stacks	NA - The facility does not have this source type.
98.236(c)(13)	For each centrifugal compressor	NA - The facility does not have this source type.
98.236(c)(14)	For reciprocating compressors	NA - The facility does not have this source type.
98.236(c)(15)	For each component type (major equipment type for onshore production) that uses emission factors for estimating emissions (refer to §98.233(q) and (r))	See response in the following subsections.
98.236(c)(15)(i)	For equipment leaks found in each leak survey (refer to §98.233(q)), report the following:	See Table B-8.
98.236(c)(15)(i)(A)	Total count of leaks found in each complete survey listed by date of survey and each component type for which there is a leaker emission factor in Tables W-2, W-3, W-4, W-5, W-6, and W-7 of this subpart.	See Table B-8.
98.236(c)(15)(i)(B)	For onshore natural gas processing, range of concentrations of CH_4 and CO_2 (refer to Equation W-30A of §98.233).	See Table B-8.
98.236(c)(15)(i)(C)	Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas (refer to Equation W-30A of §98.233), by component type.	See Table B-8.
98.236(c)(15)(ii)	For equipment leaks calculated using population counts and factors (refer to §98.233(r)), report the following:	See response in the following subsections.
98.236(c)(15)(ii)(A)	For source categories §98.230(a)(5), (a)(6), and (a)(7), total count for each component type in Tables W-4, W-5, and W-6 of this subpart for which there is a population emission factor, listed by major heading and component type.	See Table B-8.
98.236(c)(15)(ii)(B)	For onshore production (refer to §98.230 paragraph (a)(2)), total count for each type of major equipment in Table W-1B and Table W-1C of this subpart, by facility.	See Table B-8.
98.236(c)(15)(ii)(C)	Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas (refer to Equation W-31 of §98.233), by component type.	See Table B-8.
98.236(c)(16)	For local distribution companies, report the following:	See response in the following subsections.
98.236(c)(16)(i)	Total number of above grade T-D transfer stations in the facility.	See Table B-8.
98.236(c)(16)(II)	Number of years over which all T-D transfer stations will be monitored at least once.	See Table B-8.
98.236(c)(16)(iii)	Number of T-D stations monitored in calendar year.	See Table B-8.
98.236(c)(16)(iv)	Total number of below grade T-D transfer stations in the facility.	See Table B-8.
98.236(c)(16)(v)	Total number of above grade metering-regulating stations (this count will include above grade T-D transfer stations) in the facility.	See Table B-8.
98.236(c)(16)(vi)	Total number of below grade metering-regulating stations (this count will include below grade T-D transfer stations) in the facility.	See Table B-8.
98.236(c)(16)(vii)	[Reserved]	No response required.
98.236(c)(16)(viii)	Leak factor for meter/regulator run developed in Equation W-32 of §98.233.	See Table B-8.
98.236(c)(16)(ix)	Number of miles of unprotected steel distribution mains.	See Table B-8.
98.236(c)(16)(x)	Number of miles of protected steel distribution mains.	See Table B-8.
98.236(c)(16)(xi)	Number of miles of plastic distribution mains.	See Table B-8.
98.236(c)(16)(xii)	Number of miles of cast iron distribution mains.	See Table B-8.
98.236(c)(16)(xiii)	Number of unprotected steel distribution services.	See Table B-8.
98.236(c)(16)(xiv)	Number of protected steel distribution services.	See Table B-8.
98.236(c)(16)(xv)	Number of plastic distribution services.	See Table B-8.
98.236(c)(16)(xvi)	Number of copper distribution services.	See Table B-8.
98.236(c)(16)(xvii)	Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all above grade T-D transfer stations combined.	See Table B-8.
98.236(c)(16)(xviii)	Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all below grade T-D transfer stations combined.	See Table B-8.
98.236(c)(16)(xix)	Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all above grade metering-regulating stations (including T-D transfer stations) combined.	See Table B-8.
98.236(c)(16)(xx)	Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all below grade metering-regulating stations (including T-D transfer stations) combined.	See Table B-8.
98.236(c)(16)(xxi)	Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all distribution mains combined.	See Table B-8.
98.236(c)(16)(xxii)	Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all distribution services combined.	See Table B-8.
98.236(c)(17)	For each EOR injection pump blowdown	NA - The facility does not have this source type.
98.236(c)(18)	For EOR hydrocarbon liquids dissolved CO_2 for each sub-basin category	NA - The facility does not have this source type.
98.236(c)(19)	For onshore petroleum and natural gas production and natural gas distribution combustion emissions	NA - The facility does not have this source type.
98.236(d)	Report annual throughput as determined by engineering estimate based on best available data for each industry segment listed in paragraphs (a)(1) through (a)(8) of this section.	See Table B-8.
98.236(e)	For onshore petroleum and natural gas production, report the best available estimate of API gravity, best available estimate of gas to oil ratio, and best available estimate of average low pressure separator pressure for each oil sub-basin category.	NA - The facility does not have this source type.

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

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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

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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.	See Table B-10.
98.406(b)(3)	Annual volume in Mscf of vaporized liquefied natural gas (LNG) produced at on-system vaporization facilities for delivery on the distribution system that is not accounted for in paragraph (b)(1) of this section.	See Table B-10.
98.406(b)(4)	Annual volume in Mscf of natural gas withdrawn from on-system storage (that is not delivered to the city gate) for delivery on the distribution system.	See Table B-10.
98.406(b)(5)	Annual volume in Mscf of natural gas delivered directly to LDC systems from producers or natural gas processing plants from local production.	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 LDC to each meter registering supply equal to or greater than 460,000 Mscf during the calendar year.	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).	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.	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 - 2012 Greenhouse Gas Inventory

Unit	Unit ID [1]	Unit Type	Maximum Rate Heat Input Capacity (MMBtu)	Fuel Type	HI (4),(5) (MMBtu)	Acid Rain Program [2]	Emissions Include Emissions from a Cogeneration Unit Located at the Facility [2],(6)	Tier (1)	Method Start and End Date	Emissions (metric ton)			Emissions in CO_2e (metric ton)				Emissions (short ton)			Emissions in CO_2e (short ton)			
										CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	Total	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	Total
Colstrip Unit 1	1	Coal	1,047	Coal	12,802,380	Yes	NA	4	1/1/2012 - 12/31/2012	737,856.53	70.41	10.24	737,856.53	1,478.67	3,174.99	742,510.20	813,347.60	77.62	11.29	813,347.60	1,629.96	3,499.83	818,477.39
Colstrip Unit 2	2	Coal		Coal	13,310,313	Yes	NA	4	1/1/2012 - 12/31/2012	780,289.92	73.21	10.65	780,289.92	1,537.34	3,300.96	785,128.22	860,122.41	80.70	11.74	860,122.41	1,694.63	3,638.68	865,455.72
Colstrip Unit 3	3	Coal	1,262	Coal	45,267,653	Yes	NA	4	1/1/2012 - 12/31/2012	1,261,919.24	124.49	18.11	1,261,919.24	2,614.21	5,613.19	1,270,146.64	1,391,027.86	137.22	19.96	1,391,027.86	2,881.67	6,187.48	1,400,097.01
Colstrip Unit 4	4	Coal		Coal	48,586,101	Yes	NA	4	1/1/2012 - 12/31/2012	1,327,903.75	133.61	19.43	1,327,903.75	2,805.85	6,024.68	1,336,734.28	1,463,763.33	147.28	21.42	1,463,763.33	3,092.92	6,641.07	1,473,497.31
Encogen 1	CT1	Natural gas cogeneration	563	Natural Gas	337,716	Yes	Yes	4	1/1/2012 - 12/31/2012	18,220.53	0.34	0.03	18,220.53	7.09	10.47	18,238.09	20,084.70	0.37	0.04	20,084.70	7.82	11.54	20,104.05
Encogen 2	CT2	Natural gas cogeneration		Natural Gas	311,895	Yes	Yes	4	1/1/2012 - 12/31/2012	16,825.47	0.31	0.03	16,825.47	6.55	9.67	16,841.69	18,546.90	0.34	0.03	18,546.90	7.22	10.66	18,564.78
Encogen 3	CT3	Natural gas cogeneration		Natural Gas	307,227	Yes	Yes	4	1/1/2012 - 12/31/2012	16,580.17	0.31	0.03	16,580.17	6.45	9.52	16,596.14	18,276.50	0.34	0.03	18,276.50	7.11	10.50	18,294.11
Ferndale 1	CT-1A	Natural gas combined cycle	863	Natural Gas	130,809	Yes	NA	4	1/1/2012 - 12/31/2012	7,051.96	0.13	0.01	7,051.96	2.75	4.06	7,058.77	7,773.46	0.14	0.01	7,773.46	3.03	4.47	7,780.96
Ferndale 2	CT-1B	Natural gas combined cycle		Natural Gas	134,617	Yes	NA	4	1/1/2012 - 12/31/2012	7,258.08	0.13	0.01	7,258.08	2.83	4.17	7,265.08	8,000.66	0.15	0.01	8,000.66	3.12	4.60	8,008.37
Frederickson 1	F1CT	Natural gas combined cycle	464	Natural Gas	2,578,142	Yes	Yes	4	1/1/2012 - 12/31/2012	138,996.94	2.58	0.26	138,996.94	54.14	79.92	139,131.00	153,217.90	2.84	0.28	153,217.90	59.68	88.10	153,365.68
Fredonia 1	CT1	Dual-fuel combustion turbines	706	Natural Gas	NR	No	NA	2	1/1/2012 - 12/31/2012	7,652.12	0.14	0.01	7,652.12	3.03	4.47	7,659.62	8,435.02	0.16	0.02	8,435.02	3.34	4.93	8,443.29
				Distillate Fuel Oil No. 2	NR	No	NA	2	1/1/2012 - 12/31/2012	33,650.33	1.36	0.27	33,650.33	28.66	84.63	33,763.62	37,093.14	1.50	0.30	37,093.14	31.60	93.28	37,218.02
Fredonia 2	CT2	Dual-fuel combustion turbines		Natural Gas	NR	No	NA	2	1/1/2012 - 12/31/2012	3,721.15	0.07	0.01	3,721.15	1.47	2.18	3,724.79	4,101.86	0.08	0.01	4,101.86	1.62	2.40	4,105.88
				Distillate Fuel Oil No. 2	NR	No	NA	2	1/1/2012 - 12/31/2012	69,387.55	2.81	0.56	69,387.55	59.11	174.50	69,621.16	76,486.68	3.10	0.62	76,486.68	65.15	192.35	76,744.19
Fredonia 3	CT3	Dual-fuel combustion turbines	365	Natural Gas	117,098	Yes	NA	4	1/1/2012 - 12/31/2012	6,418.30	0.12	0.01	6,418.30	2.46	3.63	6,424.39	7,074.96	0.13	0.01	7,074.96	2.71	4.00	7,081.68
Fredonia 4	CT4	Dual-fuel combustion turbines		Natural Gas	149,833	Yes	NA	4	1/1/2012 - 12/31/2012	8,154.64	0.15	0.01	8,154.64	3.15	4.64	8,162.43	8,988.95	0.17	0.02	8,988.95	3.47	5.12	8,997.54
Frederickson 1	CT1	Dual-fuel combustion turbines	508	Natural Gas	NR	No	Yes	2	1/1/2012 - 12/31/2012	14,620.57	0.28	0.03	14,620.57	5.79	8.55	14,634.91	16,116.42	0.30	0.03	16,116.42	6.38	9.42	16,132.23
				Distillate Fuel Oil No. 2	NR	No	Yes	2	1/1/2012 - 12/31/2012	8,834.31	0.36	0.07	8,834.31	7.53	22.22	8,864.06	9,738.16	0.40	0.08	9,738.16	8.30	24.49	9,770.95
Frederickson 2	CT2	Dual-fuel combustion turbines		Natural Gas	NR	No	Yes	2	1/1/2012 - 12/31/2012	15,564.44	0.29	0.03	15,564.44	6.16	9.10	15,579.71	17,156.86	0.32	0.03	17,156.86	6.80	10.03	17,173.69
				Distillate Fuel Oil No. 2	NR	No	Yes	2	1/1/2012 - 12/31/2012	3,971.30	0.16	0.03	3,971.30	3.38	9.99	3,984.67	4,377.61	0.18	0.04	4,377.61	3.73	11.01	4,392.35
Goldendale	CT-1	Natural gas combined cycle	949	Natural Gas	6,034,718	Yes	Yes	4	1/1/2012 - 12/31/2012	325,354.94	6.03	0.60	325,354.94	126.73	187.08	325,668.74	358,642.43	6.65	0.67	358,642.43	139.69	206.22	358,988.34
Mint Farm	CTG1	Natural gas combined cycle	1,013	Natural Gas	8,039,461	Yes	Yes	4	1/1/2012 - 12/31/2012	433,428.11	8.04	0.80	433,428.11	168.83	249.22	433,846.16	477,772.70	8.86	0.89	477,772.70	186.10	274.72	478,233.53
Sumas	CT-1	Natural gas cogeneration	433	Natural Gas	1,976,052	Yes	Yes	4	1/1/2012 - 12/31/2012	106,537.22	1.98	0.20	106,537.22	41.50	61.26	106,639.98	117,437.19	2.18	0.22	117,437.19	45.74	67.52	117,550.45
Whitehorn 2	CT2	Dual-fuel combustion turbines	508	Natural Gas	NR	No	NA	2	1/1/2012 - 12/31/2012	13,812.83	0.26	0.03	13,812.83	5.47	8.08	13,826.38	15,226.04	0.29	0.03	15,226.04	6.03	8.90	15,240.97
				Distillate Fuel Oil No. 2	NR	No	NA	2	1/1/2012 - 12/31/2012	21,669.45	0.88	0.18	21,669.45	18.46	54.50	21,742.41	23,886.49	0.97	0.19	23,886.49	20.35	60.07	23,966.90
Whitehorn 3	CT3	Dual-fuel combustion turbines		Natural Gas	NR	No	NA	2	1/1/2012 - 12/31/2012	12,097.92	0.23	0.02	12,097.92	4.79	7.07	12,109.79	13,335.68	0.25	0.03	13,335.68	5.28	7.80	13,348.76
				Distillate Fuel Oil No. 2	NR	No	NA	2	1/1/2012 - 12/31/2012	28,382.49	1.15	0.23	28,382.49	24.18	71.38	28,478.04	31,286.34	1.27	0.25	31,286.34	26.65	78.68	31,391.67
									Total	**5,426,160.26**	**429.84**	**61.92**	**5,426,160.26**	**9,026.57**	**19,194.11**	**5,454,380.95**	**5,981,317.83**	**473.81**	**68.25**	**5,981,317.83**	**9,950.09**	**21,157.89**	**6,012,425.81**

Calculation Inputs:

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

Data Source:

[1] ECMPS Feedback (EPA).
[2] PSE.

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 - 2012 Greenhouse Gas Inventory

Component	Emission Factor [7]	(UOM)	Count [1],[2],(1)	Duration Component Leaking (hr) (2)	Emissions (metric ton)		Emissions in CO_2e (metric ton) (3)	Facility Emissions Factor (scf/hr/count)	
					CO_2	CH_4	CO_2e	CO_2	CH_4
T-D Transfer Station									
Connector	1.69	scf/hr/component	0	8,760	0 {1}	0 {1}	0	0 {3}	0 {3}
Block Valve	0.557	scf/hr/component	0	8,760	0 {1}	0 {1}	0	0 {3}	0 {3}
Control Valve	9.34	scf/hr/component	0	8,760	0 {1}	0 {1}	0	0 {3}	0 {3}
Pressure Relief Valve	0.27	scf/hr/component	0	8,760	0 {1}	0 {1}	0	0 {3}	0 {3}
Orifice Meter	0.212	scf/hr/component	0	8,760	0 {1}	0 {1}	0	0 {3}	0 {3}
Regulator	0.772	scf/hr/component	0	8,760	0 {1}	0 {1}	0	0 {3}	0 {3}
Open-ended Line	26.131	scf/hr/component	0	8,760	0 {1}	0 {1}	0	0 {3}	0 {3}
Below Grade M&R Station									
Below Grade M&R Station Components > 300 psig	1.30	scf/hr/station	2	8,760	0.01 {2}	0 {2}	9	NA	NA
Below Grade M&R Station Components 100 to 300 psig	0.20	scf/hr/station	354	8,760	0.36 {2}	12 {2}	244	NA	NA
Below Grade M&R Station Components < 100 psig	0.10	scf/hr/station	35	8,760	0.02 {2}	0.6 {2}	12	NA	NA
Distribution Mains									
Unprotected Steel	12.58	scf/hr/mile	25	8,760	1.59 {2}	52 {2}	1,085	NA	NA
Protected Steel	0.35	scf/hr/mile	3,853	8,760	6.84 {2}	221 {2}	4,651	NA	NA
Plastic	1.13	scf/hr/mile	8,197	8,760	46.95 {2}	1,519 {2}	31,945	NA	NA
Cast Iron	27.25	scf/hr/mile	7	8,760	0.97 {2}	31 {2}	658	NA	NA
Distribution Services									
Unprotected Steel	0.19	scf/hr/#services	500	8,760	0.48 {2}	16 {2}	328	NA	NA
Protected Steel	0.02	scf/hr/#services	155,764	8,760	15.79 {2}	511 {2}	10,744	NA	NA
Plastic	0.001	scf/hr/#services	648,935	8,760	3.29 {2}	106 {2}	2,238	NA	NA
Copper	0.03	scf/hr/#services	35	8,760	0.01 {2}	0.2 {2}	4	NA	NA
				Total	**76**	**2,469**	**51,917**		

Other Reporting Data:

Annual emissions in metric tons of CO_2e for the industry segment	51,917	metric tons	
Number of above grade T-D transfer stations	41		[1]
Number of years all T-D transfer stations monitored at least once	5		[2]
Number of T-D stations monitored in calendar year	41		[1]
Number of below grade T-D transfer stations	0		[1]
Number of above grade M&R stations	41		[1]
Number of below grade M&R stations	391		[1]
Annual throughput	903,534,000	thm	[3]

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_2O	NA	0.0526

Calculation Methodology:

{1} EPA GHG MRR Subpart W (40 CFR 98.233(q)) (Eq. W-30B).
{2} EPA GHG MRR Subpart W (40 CFR 98.233(r)) (Eq. W-31).
{3} EPA GHG MRR Subpart W (40 CFR 98.233(r)(6)) (Eq. W-32).

Data Source:

[1] PSE 2012 Leak Detection Survey.
[2] 2012 Annual Report for Gas Distribution System (US DOT).
[3] PSE 2012 Form 10-K (PSE, 2012).
[4] EPA GHG MRR Subpart W (40 CFR 98.233(q)) (Eq. W-30B).
[5] EPA GHG MRR Subpart W (40 CFR 98.233(r)) (Eq. W-31).
[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.

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 - 2012 Greenhouse Gas Inventory

	SF_6 Inventory (not energized)			
98.306(d)	SF_6 at the beginning of the year	5,820	lb	
98.306(e)	SF_6 at the end of the year	6,060	lb	
	Decrease in SF_6 inventory	**-240**	**lb**	{2}
	Acquisitions of SF_6			
98.306(f)	SF_6 purchased from chemical producers or distributors in bulk	230	lb	
98.306(g)	SF_6 purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear	2,432	lb	
98.306(h)	SF_6 returned to facility after off-site recycling	0	lb	
	Acquisitions of SF_6	**2,662**	**lb**	{2}
	Disbursements of SF_6			
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	2,862	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 SF_6	**2,862**	**lb**	{2}
98.306(a)	**Nameplate Capacity of Equipment Operated**			
98.306(a)(2)	Nameplate capacity of new equipment in pounds, including hermetically sealed-pressure switchgear	2,432	lb	
98.306(a)(3)	Nameplate capacity of retiring equipment in pounds, including hermetically sealed-pressure switchgear	2,862	lb	
	Net Increase in Total Nameplate Capacity of Equipment Operated	**-430**	**lb**	{2}
	User Emissions	**-10**	**lb**	
		-0.005	**metric ton**	
		-108	**metric ton CO_2e**	

Other Reporting Data:

98.306(a)(1)	Existing at the beginning of the year (excluding hermetically sealed-pressure switchgear)	115,250	lb	[1]
98.306(a)(2)	New during the year (all SF_6-insulated equipment, including hermetically sealed-pressure switchgear)	2,432	lb	[1]
98.306(a)(3)	Retired during the year (all SF_6-insulated equipment, including hermetically sealed-pressure switchgear)			[1]
		2,862	lb	
98.306(b)	Transmission miles (length of lines carrying voltages above 35 kilovolt)	831.64	lb	[1]
98.306(c)	Distribution miles (length of lines carrying voltages at or below 35 kilovolt)	21,730	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]
		5,820	lb	
98.306(e)	Pounds of SF_6 and PFC stored in containers, but not in energized equipment, at the end of the year	6,060	lb	[1]
98.306(f)	Pounds of SF_6 and PFC purchased in bulk from chemical producers or distributors	230	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]
		2,432	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	2,862	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 98.302(a)) (Eq. DD-1).

Data Source:

[1] PSE 2012 SF_6 Summary Report.

Note(s):

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

Table B-10. EPA GHG MRR Subpart NN Calculations

Puget Sound Energy - 2012 Greenhouse Gas Inventory

98.403(a) **Natural Gas Received at City Gate**

Fuel	109,521,743	Mscf	[1]
EF	0.055	metric ton/ Mscf	[2]
CO_{2i}	**6,023,696**	**metric ton**	{1}, (3)

98.403(b)(1) **Natural Gas Received for Redelivery to Downstream Gas Transmission Pipelines and Other LDC**

Fuel	21,953,155	Mscf	[3]
EF	0.055	metric ton/ Mscf	[2]
CO_{2j}	**1,207,424**	**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 #
UNIV OF WASH POWER PLANT C	1,505,851	3900 Jefferson Road	000841533
Total	**1,505,851**		

Fuel	1,505,851	Mscf	[4]
EF	0.055	metric ton/ Mscf	[2]
CO_{2k}	**82,822**	**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 Received at City Gate Injected into On-System Storage, and/or Liquefied and Stored

Fuel	25,182,925	Mscf	[5]

Natural Gas Previously Stored On-System or Liquefied and Stored that is Removed from Storage and Used for Deliveries to Customers or Other LCDs

Fuel	25,836,757	Mscf	[6]

Natural Gas Bypassed the City Gate and Inserted Directly to the PSE Distribution System

Fuel	795,564	Mscf	[4]
EF	0.055	metric ton/ Mscf	[2]
CO_{2l}	**-79,717**	**metric ton**	{4}

98.403(b)(4) **Total CO_2 Emissions**

CO_2	**4,813,167**	**metric ton**	{5}

Other Reporting Data:

98.402(b)	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	4,813,167	metric ton	
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	109,521,743	Mscf	
98.406(b)(2)	Annual volume in Mscf of natural gas placed into storage	25,182,925	Mscf	
98.406(b)(3)	Annual volume in Mscf of vaporized liquefied natural gas (LNG) produced at on-system vaporization facilities for delivery on the distribution system that is not accounted for in paragraph (b)(1) of this section	0	Mscf	
98.406(b)(4)	Annual volume in Mscf of natural gas withdrawn from on-system storage (that is not delivered to the city gate) for delivery on the distribution system	25,836,757	Mscf	
98.406(b)(5)	Annual volume in Mscf of natural gas delivered directly to LDC systems from producers or natural gas processing plants from local production	795,564	Mscf	
98.406(b)(6)	Annual volume in Mscf of natural gas delivered to downstream gas transmission pipelines and other local distribution companies	21,953,155	Mscf	
98.406(b)(7)	Annual volume in Mscf of natural gas delivered by LDC to each meter registering supply equal to or greater than 460,000 Mscf during the calendar year	1,505,851	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)	-79,717	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)	82,822	metric ton	
98.406(b)(13)(i)	Residential consumers	54,231,428	Mscf	[7]
98.406(b)(13)(ii)	Commercial consumers	33,963,438	Mscf	[8]
98.406(b)(13)(iii)	Industrial consumers	20,779,352	Mscf	[9]
98.406(b)(13)(iv)	Electricity generating facilities	0	Mscf	[10]

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-5).
{5} EPA GHG MRR Subpart NN (40 CFR 98.403(2)) (Eq. NN-6).

Data Source:

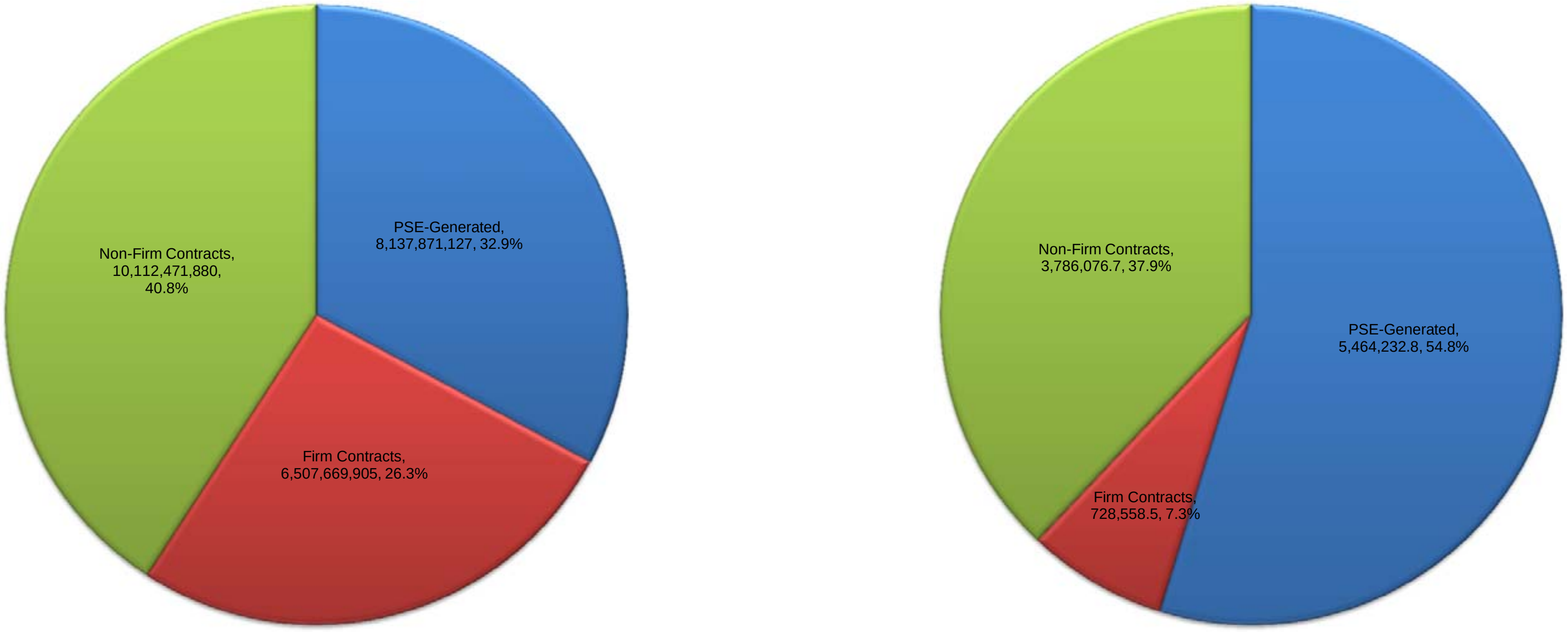
[1] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2012), Box 4.4.
[2] EPA GHG MRR Subpart NN (40 CFR 98.408), Table NN-2.
[3] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2012), Box 11.2, 11.3.
[4] PSE.
[5] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2012), Box 13.1.
[6] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2012), Box 2.1.
[7] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2012), Box 10.1, 11.1.
[8] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2012), Box 10.2, 11.2.
[9] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2012), Box 10.3, 11.3.
[10] Annual Report of Natural and Supplemental Gas Supply and Distribution, Form EIA-176 (2012), Box 10.4, 11.4.

Note(s):

(1) Reporters to EPA must use one of two methods to calculate the CO_2 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 CO_2 emissions factor, and is most appropriate for liquid fuels. The second method (Equations NN-2) uses either a measured or default CO_2 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 - 2012 Greenhouse Gas Inventory

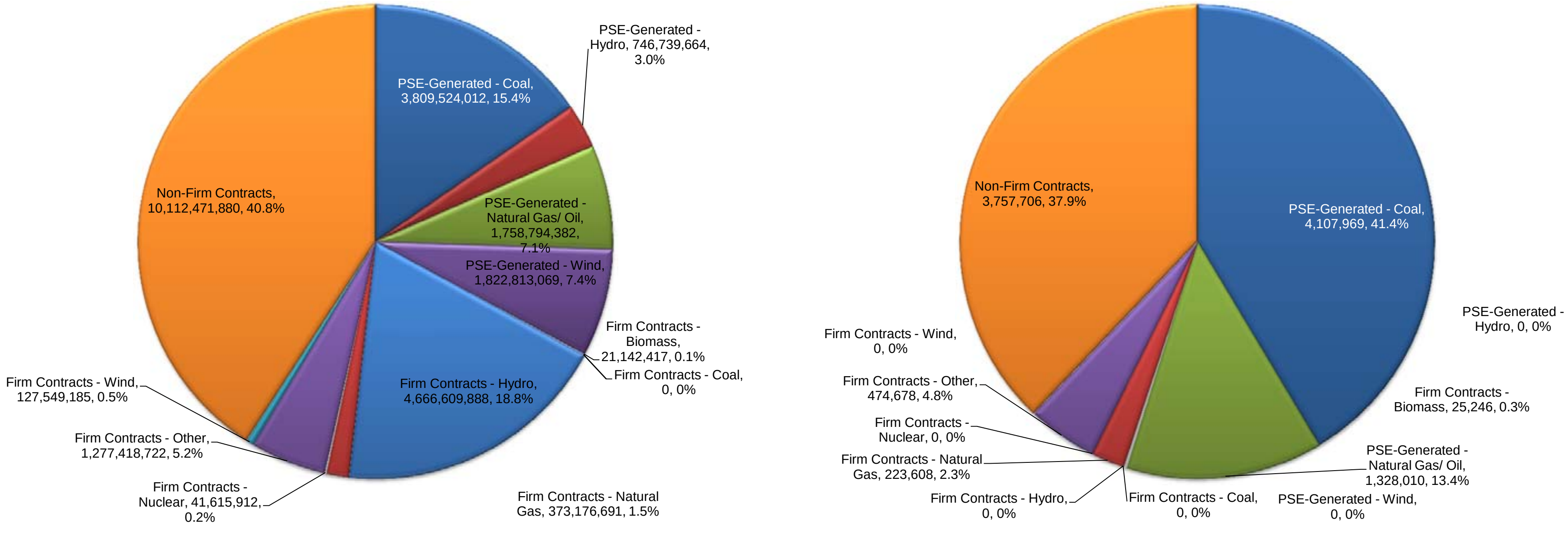


Electricity (kWh)

CO_2 Emissions (metric ton)

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

Puget Sound Energy - 2012 Greenhouse Gas Inventory

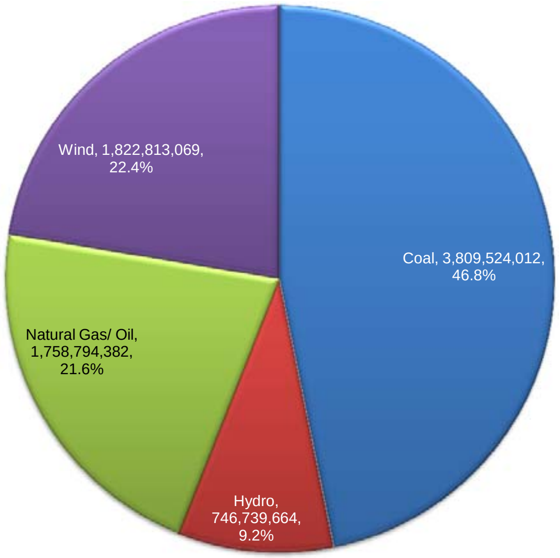


Electricity (kWh)

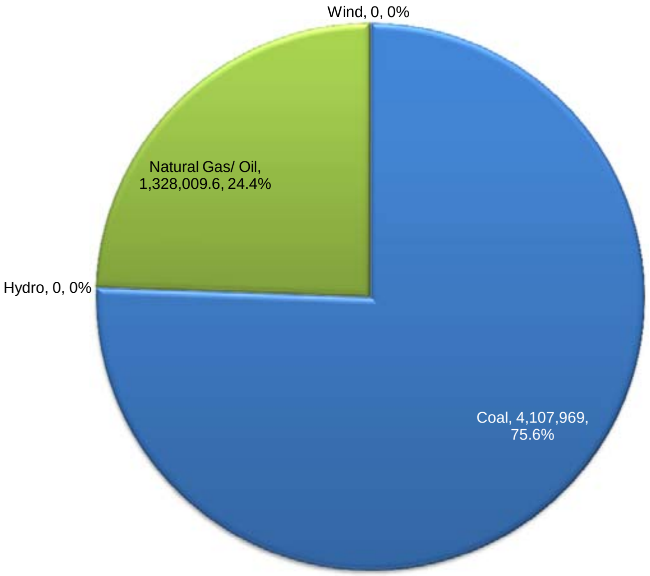
CO_2 Emissions (metric ton)

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

Puget Sound Energy - 2012 Greenhouse Gas Inventory



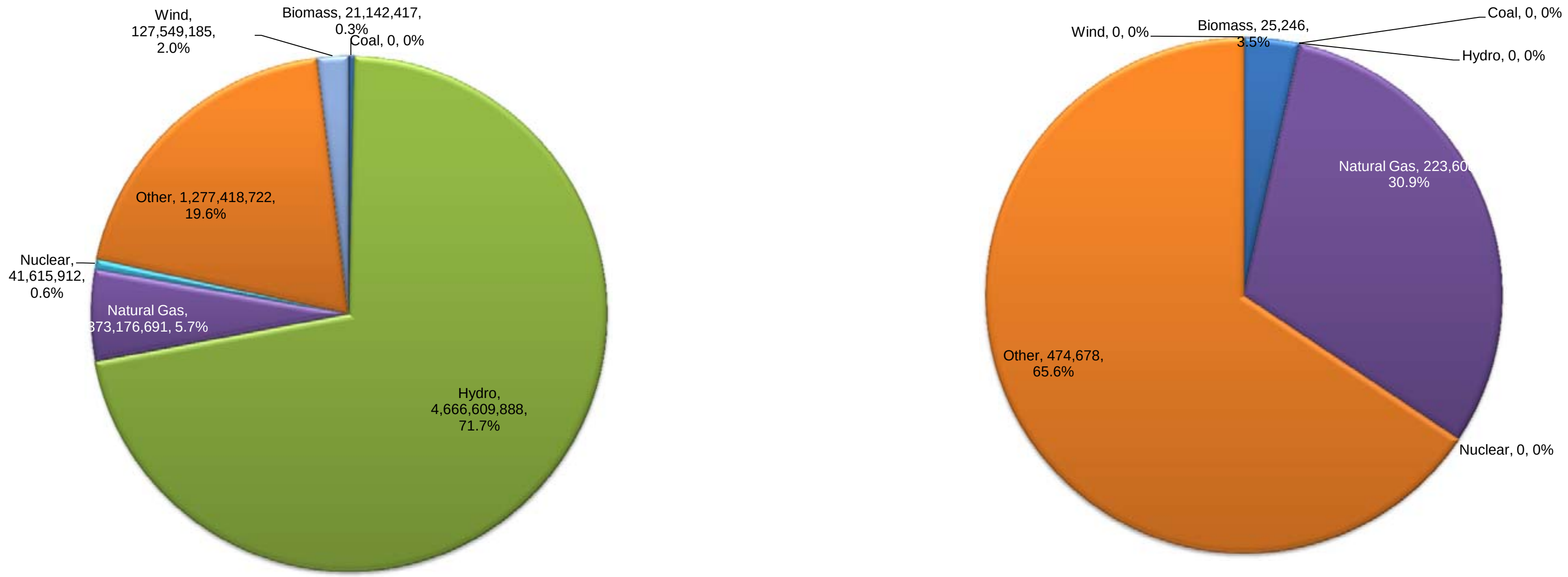
Electricity (kWh)



CO_2 Emissions (metric ton)

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

Puget Sound Energy - 2012 Greenhouse Gas Inventory

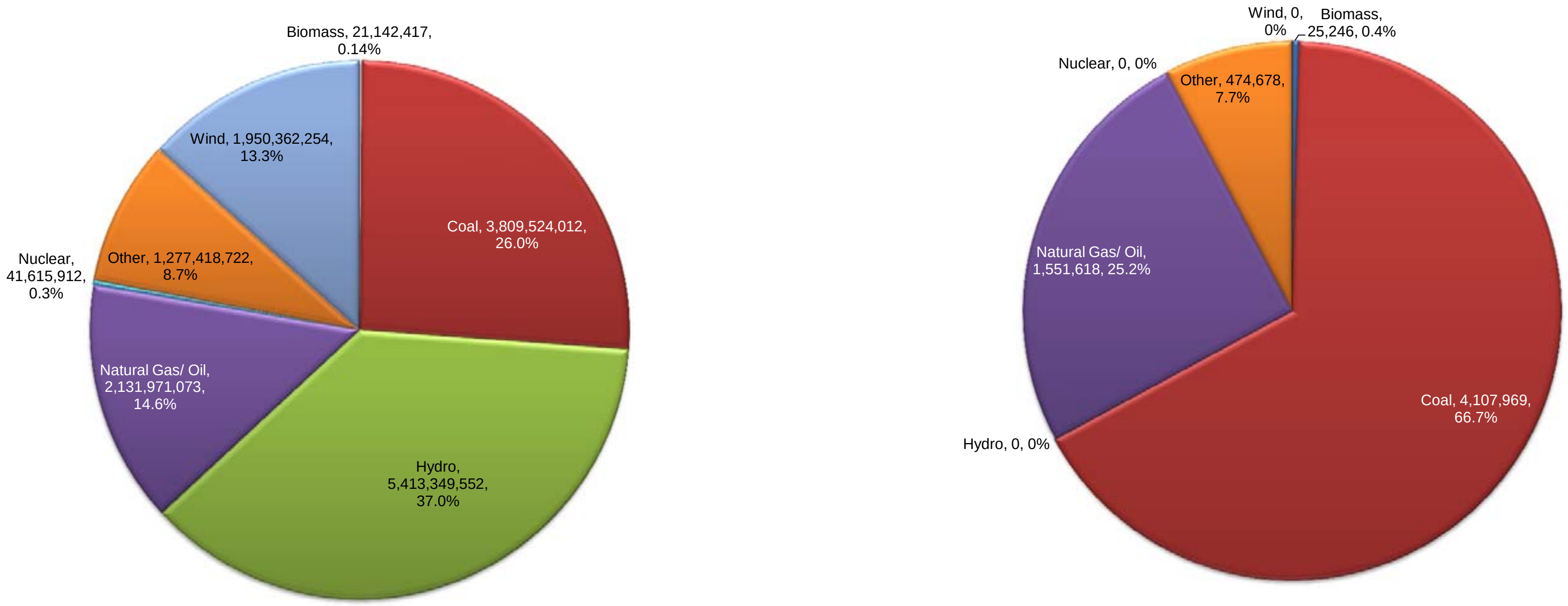


Electricity (kWh)

CO_2 Emissions (metric ton)

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

Puget Sound Energy - 2012 Greenhouse Gas Inventory

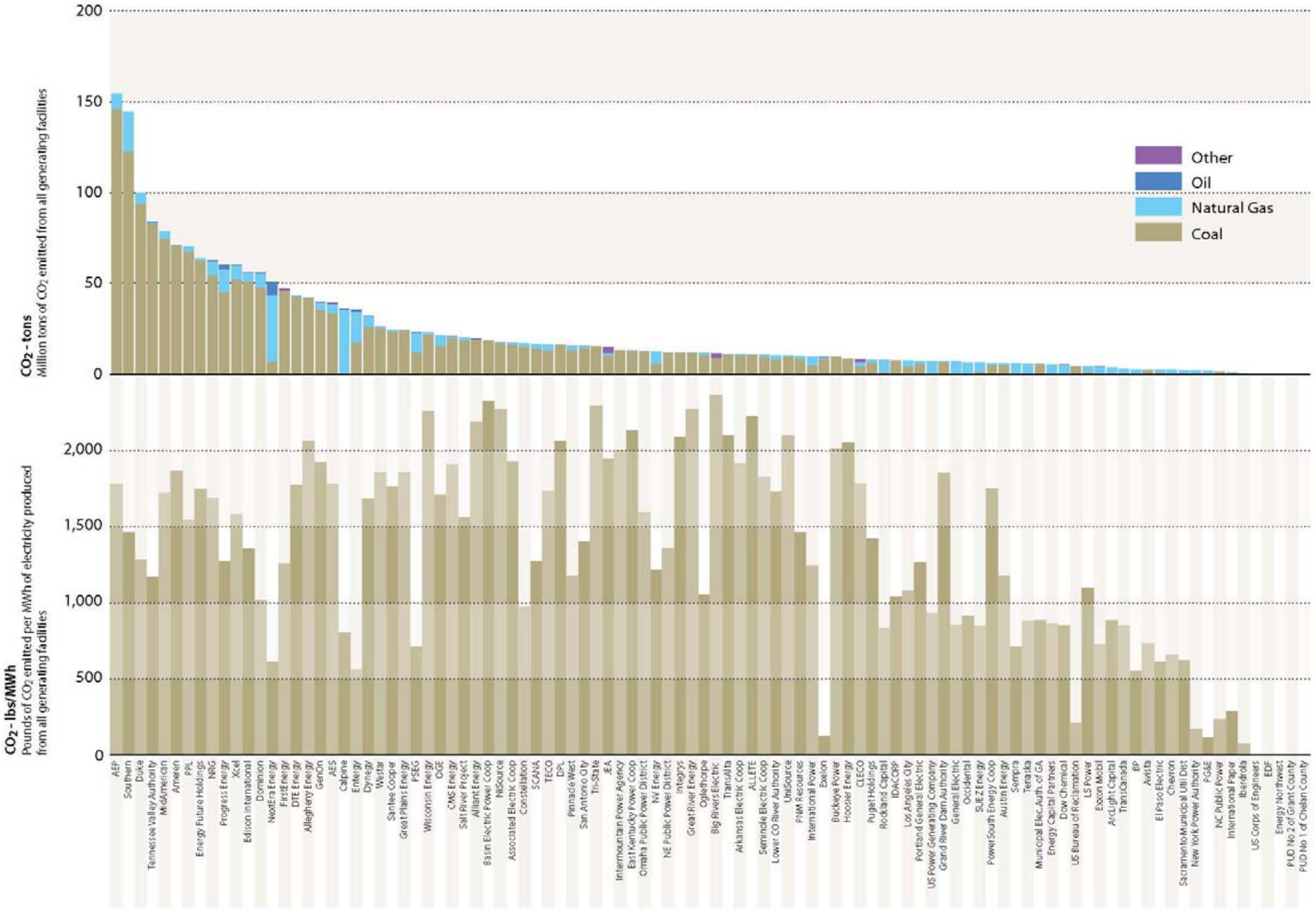


Electricity (kWh)

CO_2 Emissions (metric ton)

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

Puget Sound Energy - 2012 Greenhouse Gas Inventory



Data Source:

(1) CERES/ NRDCl/ PSEG/ PG&E Corporation, Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States, Figure 16, July 2012.