THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)

Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)

Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Puget Sound Energy, Inc.	**End of** 2018/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ____________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Puget Sound Energy, Inc.	02 Year/Period of Report End of 2018/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* P.O. BOX 97034, Bellevue, WA 98009-9734	
05 Name of Contact Person Stephen J King	06 Title of Contact Person Controller and PAO
07 Address of Contact Person *(Street, City, State, Zip Code)* P.O. BOX 97034, Bellevue, WA 98009-9734	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(425) 456-2008	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Stephen King	Stephen King	04/16/2019
02 Title Controller and PAO		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	N/A
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	N/A
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [ ] Two copies will be submitted [X] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Puget Sound Energy, Inc.
Stephen J King, Controller and Principal Accounting Officer
P.O. Box 97034 PSE-08S
Bellevue, WA 98009-9734

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Washington, September 12, 1960

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric - State of Washington
Natural Gas - State of Washington

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Puget Energy, Inc., an energy services holding company, holds all outstanding shares of Puget Sound Energy, Inc. common stock. Puget Energy, Inc. is the direct wholly owned subsidiary of Puget Equico, LLC, which is a directly wholly owned subsidiary of Puget Intermediate Holdings, Inc. which is in turn a direct wholly owned subsidiary of Puget Holdings, LLC.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Puget Western, Inc.	Real Estate Operations	100	
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President & Chief Executive Officer	Kimberly J. Harris	939,823
2	Sr. V.P. & Chief Financial Officer	Daniel A. Doyle	519,039
3	Sr. V.P. & Chief Administrative Officer	Marla D. Mellies	351,428
4	Sr. V.P., G.C., & Chief Ethics & Compliance Officer	Steve R. Secrist	436,600
5	V.P. Chief Information Officer	Margaret Hopkins	301,035
6	V.P. Operations & Communications	Andy W. Wappler	266,431
7	Sr. V.P. Operations	Booga K. Glibertson	330,201
8	Sr. V.P. Energy Operations	David E. Mills	332,006
9	Sr. V.P. & Chief Customer Officer	Philip K Bussesy	311,388
10	V.P. Regulatory & Government Affiars	Ken Johnson	249,745
11	Director, Tax	Matthew Marcelia	216,397
12	Controller & Principal Accounting Officer	Stephen J. King	180,597
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			

Schedule Page: 104 Line No.: 9 Column: a

Mr. Philip K Bussey, Senior Vice President and Chief Customer Officer of Puget Sound Energy, Inc retired from the Company on January 5, 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Scott Armstrong	Seattle, Washington
2	Andrew Chapman	New York, New York
3	Kimberly Harris, President & CEO	Bellevue, Washington
4	Steven W. Hooper	Bellevue, Washington
5	Christopher Hind	Toronto, Ontario, Canada
6	Christopher Leslie	New York, New York
7	David MacMillian	London, England
8	Paul McMillan	Calgary, Alberta, Canada
9	Mary McWilliams	Seattle, Washington
10	Etienne Middleton	Toronto, Ontario, Canada
11	Christopher Trumpy	Victoria, British Columbia, Canada
12	Barbara Gordon	Bellevue, Washington
13	Karl Kuchel	New York, New York
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
48		

Schedule Page: 105 Line No.: 7 Column: a

Mr. David MacMillan, director on the Boards of Directors of Puget Energy, Inc and its wholly owned subsidiary, Puget Sound Energy, Inc tendered his resignation from the Company effective on January 18, 2018.

Schedule Page: 105 Line No.: 10 Column: a

Mr. Etienne Middelton, a member of the Boards of Directors of Puget Energy, Inc and it's wholly owned subsidiary, Puget Sound Energy, Inc tendered his resignation from the Boards effective on August 2, 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff	FERC Docket No. ER12-778-001
2	FERC Electric Tariff Amendment	FERC Docket No. ER18-1249-000
3		Amendment to OATT Schedules
4		7, 8, and 10 to revise depreciation rates.
5		Letter order issued May 19, 2018 accepting tariff
6		revisions.
7		(Accession No. 201803305155).
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[ ] Yes
[X] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20180601-5313	06/01/2018	ER12-778-001	Informational Filing of Annual Update	FERC Electric Tariff
2	20180529-5249	05/16/2018	ER18-1695-000	Petition for limited waiver of tariff	FERC Electric Tariff
3				Order granting petition issued on Dec.	
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					

Schedule Page: 1061 Line No.: 1 Column: e

Pursaunt to the PSE OATT formula rate protocols, PSE performs an Annual Update to the formula rate which is filed at FERC. However FERC does not send an approval letter or issue a new docket number for the Annual Update.

Schedule Page: 1061 Line No.: 2 Column: e

In 2018, PSE filed an amendment to the OATT formula rate, amending the depreciation rates. FERC accepted the amendment filing in 2018, effective December 19, 2017.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.

Location (WA)	County	Type	Category	Initial Term	Consideration
Bellevue	King	Electric	New	10 years	$ -
Bremerton	Kitsap	Electric	Extension	1 year	$ -
Shoreline	King	Electric & Natural Gas	Extension	1 year	$ -
Federal Way	King	Natural Gas	Expired	-	$ -
Fife	Pierce	Natural Gas	Expired	-	$ -
Langley	Island	Electric	Expired	-	$ -
North Bend	King	Electric	Expired	-	$ -

No consideration was paid to the granting jurisdictions for any of the franchises listed above.

2. None.

3. None.

4. None.

5. None.

6. As of December 31, 2018, no amounts were drawn and outstanding under PSE's credit facility. No letters of credit were outstanding and $379.3 million was outstanding under the commercial paper program. Outside of the credit agreement, PSE had a $3.0 million letter of credit in support of a long-term transmission contract and a $1.0 million letter of credit in support of natural gas purchases in Canada.

PSE has in effect a shelf registration statement ("the existing shelf") under which it may issue, as of the date of this report, up to $200.0 million aggregate principal amount of senior notes secured by first mortgage bonds. The existing shelf will expire in November 2019. Substantially all utility properties owned by PSE are subject to the lien of the Company’s electric and natural gas mortgage indentures. To issue additional first mortgage bonds under these indentures, PSE’s earnings available for interest must exceed certain minimums as defined in the indentures. At December 31, 2018, the earnings available for interest exceeded the required amount.

On March 5, 2018, PSE commenced a tender offer and related consent solicitation to purchase any and all of the outstanding $250.0 million 6.974% Series A Enhanced Junior Subordinated Notes due June 1, 2067. Holders of the notes received $1,005 per $1,000 principal amount of notes plus accrued and unpaid interest for notes tendered and accepted by the early tender payment deadline of March 16, 2018. Holders of notes tendered after the early tender payment deadline, but prior to the tender offer expiration on April 2, 2018 were to receive the tender offer consideration of $975 per $1,000 of principal amount of the notes plus accrued but unpaid interest. A total of $193.4 million in principal amount of notes were tendered by the early payment deadline and no notes were tendered after the early payment deadline. On March 20, 2018, $194.9 million was paid to the holders of the tendered notes. This amount included the principal, early tender consideration and accrued interest up to, but not including March20, 2018.

Concurrently with the tender offer, PSE solicited consents from a majority (in principal amount) of the holders of PSE’s 6.274% Senior Notes due March 15, 2037 to terminate the replacement capital covenant granted to the holders of those notes. The termination of the covenant was necessary because it included restrictions related to repurchases, redemptions and repayments of the 6.974% Series A Enhanced Junior Subordinated Notes. PSE received consents from holders of 87.7% of the 6.274% Senior Notes and paid a consent fee totaling $2.6 million to those holders on March 19, 2018.

On March 28, 2018, PSE issued a notice of redemption, effective April 27, 2018, for the remaining $56.6 million principal amount of the 6.974% Series A Enhanced Junior Subordinated Notes. The notes were redeemed at a price equal to 100% of their principal amount plus accrued and unpaid interest up to, but excluding the redemption date.

On June 4, 2018, PSE issued $600.0 million of 30-year Senior Notes under its senior note indenture at an interest rate of 4.223% with a maturity date of June 15, 2048. The proceeds from the issuance were used to pay the principal and accrued interest on the Company's $200.0 million Secured Notes that matured on June 15, 2018, outstanding commercial paper borrowings of $348.0 million and other general corporate expenses.

7. None.

8. Non-represented employees received on average a 2.85% increase effective March 1, 2018. Employees of the UA received a 3.0% salary increase that went into effect October 1, 2018. The current contracts with the IBEW will expire March 31, 2020 and September 30, 2021, respectively. The estimated annual effect of these changes is $6.1 million.

9. Legal Proceedings:

Expedited Rate Filing Rate Adjustment - On November 7, 2018, PSE filed an expedited rate filing (ERF) with the Washington Commission. The filing is a request to change rates associated with PSE's delivery and fixed production costs. It does not include variable power costs, purchased gas costs or natural gas pipeline replacement program costs, which are recovered in separate mechanisms. The filing is based on historical test year costs and rate base, and follows the reporting requirements of a Commission Basis Report, as defined by the Washington Administrative Code, but is filed using end of period rate base and certain annualizing adjustments. It does not include any forward-looking or pro-forma adjustments. Included in the filing is a reduction to the overall authorized rate of return from 7.6% to 7.49% to recognize a reduction in debt costs associated with recent debt activity. PSE requested an overall increase in electric rates of $18.9 million annually, which is a 0.9% increase, and an overall increase in natural gas rates of $21.7 million annually, which is a 2.7% increase.

On January 22, 2019, all parties in the proceeding reached an agreement on settlement terms that resolve all issues in the filing. The settlement agreement was filed on January 30, 2019. The major points covered by the agreement are as follows. The agreed upon rate increases in the settlement are $21.5 million on natural gas and no rate increase on electric which would become effective March 1, 2019. Items that were not specifically identified in the settlement are deemed to offset the ARAM amounts discussed below to arrive at the settlement rate changes.

The settlement agreement in PSE's pending expedited rate change filing provides for the pass back beginning March 1, 2018 of the turnaround of plant related excess deferred income taxes on the average rate assumption method (ARAM) that resulted from the Tax Cuts and Jobs Act based on 2018 amounts in the amount of $6.1 million for natural gas and $25.9 million for electric. The settlement agreement leaves the determination for the regulatory treatment of the remaining items related to the TCJA to PSE's next GRC:

1) excess deferred taxes for non-plant- related book/tax differences,
2) the deferred balance associated with the over-collection of income tax expense for the period January 1 through April 30, 2018 (the time period that encompasses the effective date of the TCJA through May 1, 2018, the requested effective date of the rate change); and
3) the turnaround of plant related excess deferred income taxes using the ARAM method for the period from January 2018 through February 2019, the rate effective date for the ERF.

The agreement provides that PSE may defer the depreciation expense associated with PSE's ongoing investment in its advanced metering infrastructure (AMI) investment and to defer the return on the AMI investment that was included in the test year of the filing. The agreement preserves the parties' rights to argue that both deferrals should be or should not be recovered in the Company's next GRC. The rate of return adopted in the settlement is the 7.49% included in the filing. The Washington Commission has suspended the procedural calendar in the proceeding and indicated it will not require a settlement hearing and will make their decision on whether or not to approve the settlement on the paper record in the filing. A ruling by the Washington Commission is expected in enough time to implement rates on March 1, 2019.

Washington Commission Tax Deferral Filing - The Tax Cuts and Jobs Act (TCJA) was signed into law in December 2017. As a result of this change, PSE re-measured its deferred tax balances under the new corporate tax rate. PSE filed an accounting petition on December 29, 2017 requesting deferred accounting treatment for the impacts of tax reform. The requested deferral accounting treatment results in the tax rate change being captured in the deferred income tax balance with an offset to the regulatory liability for deferred income taxes. Additionally, on March 30, 2018, PSE filed for a rate change for electric and natural gas customers associated with TCJA to reflect the decrease in the federal corporate income tax rate from 35.0% to 21.0%. The overall impact of the rate change, based on the annual period from May 2018 through April 2019, is a revenue decrease of $72.9 million, or 3.4% for electric and $23.6 million, or 2.7% for natural gas.

The March 30, 2018, rate change filing did not address excess deferred taxes or the deferred balance associated with the over-collection of income tax expense of $34.6 million for the period January 1 through April 30, 2018 (the time period that encompasses the effective date of the TCJA through May 1, 2018, the effective date of the rate change). The $34.6 million tax over-collection decreased PSE's revenue and increased the regulatory liability for a refund to customers.

As a result of the ERF settlement, the excess deferred taxes associated with non-plant-related book/tax differences, the deferred balance associated with the over-collection of income tax expense and the treatment of the excess deferred taxes associated with plant related book/tax differences from January 1, 2018 through February 28, 2019 will be addressed in PSE’s accounting petition in its next GRC.

Washington Clean Air Rule - The CAR was adopted in September 2016, in Washington State and attempts to reduce greenhouse gas emissions from “covered entities” located within Washington State. Included under the new rule are large manufacturers, petroleum producers and natural gas utilities, including PSE. The CAR sets a cap on emissions associated with covered entities, which decreases over time approximately 5.0% every three years. Entities must reduce their carbon emissions, or purchase emission reduction units (ERUs), as defined under the rule, from others.

In September 2016, PSE, along with Avista Corporation, Cascade Natural Gas Corporation and NW Natural, filed a lawsuit in the U.S. District Court for the Eastern District of Washington challenging the CAR. In September 2016, the four companies filed a similar challenge to the CAR in Thurston County Superior Court. In March 2018, the Thurston County Superior Court invalidated the CAR. The Department of Ecology appealed the Superior Court decision in May 2018. As a result of the appeal, direct review to the Washington State Supreme Court was granted and oral argument will be in the end of March 2019. The federal court litigation has been held in abeyance pending resolution of the state case.

10. Related Party Transactions

PSE is a public utility incorporated in the state of Washington that furnishes electric and natural gas services in a territory covering approximately 6,000 square miles, primarily in the Puget Sound region. PSE’s parent company - Puget Energy - has a wholly-owned non-regulated subsidiary, Puget LNG, LLC (Puget LNG), which has the sole purpose of owning, developing and financing the non-regulated activity of the Tacoma liquefied natural gas (LNG) facility, currently under construction. PSE and Puget LNG are considered related parties with similar ownership by Puget Energy. Therefore, capital and operating costs that are incurred by PSE and allocated to Puget LNG are related party transactions by nature.

Scott Armstrong serves on the Board of Directors of the Company and, until its acquisition by Kaiser Permanente on February 1, 2017, was the President and Chief Executive Officer of Group Health Cooperative (Group Health), a health insurance and medical care provider. Certain employees of PSE elected Group Health as their medical provider prior to its acquisition by Kaiser Permanente and as a result, PSE paid Group Health a total of $3.9 million and $23.3 million for medical coverage for the year ended December 31, 2017 and 2016. Kaiser Permanente is not considered a related party to PSE.

11. Reserved.

12. None.

13. Mr. David MacMillan, director on the Board of Directors of Puget Sound Energy, Inc. tendered his resignation from the Company effective on January 18, 2018. Mr. MacMillan served in that role since November 6, 2012 and was also a member of the Audit

Committee. Mr. MacMillan served on the board of PSE as a representative of Canada Pension Plan Investment Board (CPPIB)'s ownership interests.

Mr. Phillip K. Bussey, Senior Vice President and Chief Customer Officer of Puget Sound Energy, Inc. (the "Company"), retired from the Company on January 5, 2018. Mr. Bussey served in that role since March 2012, and had served the Company as Senior Vice President, Corporate Affairs from 2003 to 2009.

Mr. Etienne Middleton, a member of the Board of Directors for Puget Sound Energy, Inc. tendered his resignation from the Board effective on August 2, 2018. Mr. Middleton had served as a director on the Board since March 1, 2016, as an appointee of the Canada Pension Plan Investment Board, one of the consortium of investors that indirectly owns Puget Sound Energy.

14. None.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	15,375,856,926	14,581,684,052
3	Construction Work in Progress (107)	200-201	550,466,420	495,937,269
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		15,926,323,346	15,077,621,321
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	6,013,978,491	5,617,411,819
6	Net Utility Plant (Enter Total of line 4 less 5)		9,912,344,855	9,460,209,502
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		9,912,344,855	9,460,209,502
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		8,654,564	8,654,564
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		3,200,905	3,106,846
19	(Less) Accum. Prov. for Depr. and Amort. (122)		20,713	20,713
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	24,740,583	25,282,015
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		49,502,086	48,473,452
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		20,175,526	20,167,625
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		2,512,359	2,157,991
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		100,110,746	99,167,216
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		34,727,116	24,969,139
36	Special Deposits (132-134)		14,058,058	5,700,640
37	Working Fund (135)		3,991,806	4,363,344
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		546,625	2,601,890
40	Customer Accounts Receivable (142)		187,008,727	237,229,841
41	Other Accounts Receivable (143)		140,877,616	94,860,942
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		8,408,670	8,900,746
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		8,535,302	3,368,040
45	Fuel Stock (151)	227	19,826,388	17,266,161
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	116,613,588	107,473,644
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	277,440	150,639
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	22,556	32,064

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	-456,332	-502,989
55	Gas Stored Underground - Current (164.1)		31,860,027	31,092,338
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		65,133	75,973
57	Prepayments (165)		35,275,821	26,460,123
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		205,285,105	222,186,152
62	Miscellaneous Current and Accrued Assets (174)		0	14,000
63	Derivative Instrument Assets (175)		49,019,225	24,405,007
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		2,512,359	2,157,991
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		836,613,172	790,688,211
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		26,727,401	27,275,211
70	Extraordinary Property Losses (182.1)	230a	118,330,539	128,508,500
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	3,786,308
72	Other Regulatory Assets (182.3)	232	444,071,714	512,468,361
73	Prelim. Survey and Investigation Charges (Electric) (183)		21,333	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		190,335	186,390
78	Miscellaneous Deferred Debits (186)	233	187,854,739	195,471,307
79	Def. Losses from Disposition of Utility Plt. (187)		168,103	248,878
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		42,377,721	39,674,090
82	Accumulated Deferred Income Taxes (190)	234	1,276,161,014	1,375,504,644
83	Unrecovered Purchased Gas Costs (191)		9,921,988	-16,050,963
84	Total Deferred Debits (lines 69 through 83)		2,105,824,887	2,267,072,726
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		12,963,548,224	12,625,792,219

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [x] An Original (2) [ ] A Resubmission	04/16/2019	end of 2018/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	859,038	859,038
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		478,145,250	478,145,250
7	Other Paid-In Capital (208-211)	253	2,804,096,691	2,804,096,691
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	7,133,879	7,133,879
11	Retained Earnings (215, 215.1, 216)	118-119	642,598,308	471,275,893
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-19,756,868	-19,215,436
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-190,884,863	-126,904,052
16	Total Proprietary Capital (lines 2 through 15)		3,707,923,677	3,601,123,505
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	3,923,860,000	3,773,860,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		6,849,516	1,758,560
24	Total Long-Term Debt (lines 18 through 23)		3,917,010,484	3,772,101,440
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		789,154	619,538
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		-225,000	2,290,000
29	Accumulated Provision for Pensions and Benefits (228.3)		101,089,892	58,840,022
30	Accumulated Miscellaneous Operating Provisions (228.4)		140,915,093	160,945,987
31	Accumulated Provision for Rate Refunds (229)		34,578,500	0
32	Long-Term Portion of Derivative Instrument Liabilities		11,094,245	21,235,027
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		180,489,049	188,933,731
35	Total Other Noncurrent Liabilities (lines 26 through 34)		468,730,933	432,864,305
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		379,297,000	329,463,000
38	Accounts Payable (232)		506,308,451	397,018,979
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		183,621	0
41	Customer Deposits (235)		42,029,654	45,143,005
42	Taxes Accrued (236)	262-263	116,841,727	114,841,147
43	Interest Accrued (237)		43,950,570	47,836,634
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		7,377,211	1,436,537
48	Miscellaneous Current and Accrued Liabilities (242)		24,929,141	22,901,624
49	Obligations Under Capital Leases-Current (243)		525,359	509,713
50	Derivative Instrument Liabilities (244)		57,755,823	86,094,157
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		11,094,245	21,235,027
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,168,104,312	1,024,009,769
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		93,054,782	88,764,092
57	Accumulated Deferred Investment Tax Credits (255)	266-267	0	0
58	Deferred Gains from Disposition of Utility Plant (256)		1,674,794	2,277,159
59	Other Deferred Credits (253)	269	313,584,370	316,010,348
60	Other Regulatory Liabilities (254)	278	1,088,713,709	1,141,625,470
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		1,998,720,901	2,034,328,346
64	Accum. Deferred Income Taxes-Other (283)		206,030,262	212,687,785
65	Total Deferred Credits (lines 56 through 64)		3,701,778,818	3,795,693,200
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		12,963,548,224	12,625,792,219

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	3,293,830,865	3,435,372,062		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,664,295,805	1,677,205,038		
5	Maintenance Expenses (402)	320-323	173,363,458	178,934,753		
6	Depreciation Expense (403)	336-337	450,723,964	406,277,451		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	7,859,026	7,510,975		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	86,037,315	58,916,375		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	11,656,401	11,657,189		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		35,645,161	20,885,273		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		21,433,427	-39,397,625		
13	(Less) Regulatory Credits (407.4)		33,645,163	42,123,699		
14	Taxes Other Than Income Taxes (408.1)	262-263	335,917,730	360,108,462		
15	Income Taxes - Federal (409.1)	262-263	54,348,132	78,605,640		
16	- Other (409.1)	262-263	437,582	16,513		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	223,098,926	1,018,195,205		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	193,749,349	835,746,783		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)		729,404	696,064		
21	Losses from Disp. of Utility Plant (411.7)		81,967	146,780		
22	(Less) Gains from Disposition of Allowances (411.8)		4,419	12,569		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		3,716,812	5,456,832		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,840,487,371	2,905,939,746		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		453,343,494	529,432,316		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
2,443,083,188	2,437,612,690	850,747,677	997,759,372			2
						3
1,218,665,540	1,163,650,904	445,630,265	513,554,134			4
146,329,474	152,131,238	27,033,984	26,803,515			5
333,758,359	276,018,010	116,965,605	130,259,441			6
7,708,442	7,379,824	150,584	131,151			7
59,676,651	42,090,325	26,360,664	16,826,050			8
11,656,401	11,657,189					9
35,645,161	20,885,273					10
						11
12,780,372	-39,719,153	8,653,055	321,528			12
33,645,163	42,123,699					13
234,352,537	245,625,339	101,565,193	114,483,123			14
22,590,030	61,577,668	31,758,102	17,027,972			15
251,525	16,513	186,057				16
177,018,210	718,619,867	46,080,716	299,575,338			17
138,110,502	584,783,510	55,638,847	250,963,273			18
						19
755,389	637,284	-25,985	58,780			20
-8,354	127,721	90,321	19,059			21
4,419	12,569					22
						23
3,557,679	5,418,936	159,133	37,896			24
2,091,466,554	2,037,922,592	749,020,817	868,017,154			25
351,616,634	399,690,098	101,726,860	129,742,218			26

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/16/2019	End of 2018/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		453,343,494	529,432,316		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		501,689	398,020		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		363,014	363,889		
33	Revenues From Nonutility Operations (417)		39,203,175	41,317,166		
34	(Less) Expenses of Nonutility Operations (417.1)		44,832,238	45,309,854		
35	Nonoperating Rental Income (418)		41,250			
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-541,432	-2,245,730		
37	Interest and Dividend Income (419)		6,407,864	7,280,801		
38	Allowance for Other Funds Used During Construction (419.1)		17,190,558	15,027,424		
39	Miscellaneous Nonoperating Income (421)		27,336,459	-23,281,393		
40	Gain on Disposition of Property (421.1)		67,090	201,437		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		45,011,401	-6,976,018		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		61,557	45,969		
46	Life Insurance (426.2)		-1,763,633	-2,361,237		
47	Penalties (426.3)		447,169	-500,400		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		6,511,722	5,085,931		
49	Other Deductions (426.5)		-9,128,046	19,813,769		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		-3,871,231	22,084,032		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	434,470	344,832		
53	Income Taxes-Federal (409.2)	262-263	-35,064,733	-77,478,306		
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,773,037	28,134,381		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-32,857,226	-48,999,093		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		81,739,858	19,939,043		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		209,707,869	217,547,317		
63	Amort. of Debt Disc. and Expense (428)		2,183,068	2,668,381		
64	Amortization of Loss on Reaquired Debt (428.1)		2,244,801	2,665,186		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		17,479,096	17,262,663		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		13,695,291	10,826,232		
70	Net Interest Charges (Total of lines 62 thru 69)		217,919,543	229,317,315		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		317,163,809	320,054,044		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		317,163,809	320,054,044		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		448,721,521	354,521,201
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Stranded Taxes due to Tax Reform		27,333,181	
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		27,333,181	
10	License Hydro Project Excess Earnings		-6,228,008	(2,315,206)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-6,228,008	(2,315,206)
16	Balance Transferred from Income (Account 433 less Account 418.1)		317,705,240	322,299,774
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Dividends Declared		-173,716,006	(227,784,248)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-173,716,006	(227,784,248)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			2,000,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		613,815,928	448,721,521
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		28,782,380	22,554,372
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		28,782,380	22,554,372
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		642,598,308	471,275,893
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-19,215,435	(14,969,705)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-541,433	(2,245,730)
51	(Less) Dividends Received (Debit)			2,000,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		-19,756,868	(19,215,435)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	317,163,809	320,054,044
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	535,046,680	460,258,798
5	Amortization of		
6	Utility Plant Adjustments	11,656,401	11,657,189
7	Property Losses	35,645,161	13,204,086
8	Deferred Income Taxes (Net)	31,142,231	173,660,328
9	Investment Tax Credit Adjustment (Net)		-53,331,101
10	Net (Increase) Decrease in Receivables	15,941,390	14,754,325
11	Net (Increase) Decrease in Inventory	-12,620,970	7,641,254
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	108,982,873	31,984,252
14	Net (Increase) Decrease in Other Regulatory Assets	-117,733,917	-52,400,197
15	Net Increase (Decrease) in Other Regulatory Liabilities	-10,070,155	138,487,128
16	(Less) Allowance for Other Funds Used During Construction	17,190,558	15,027,425
17	(Less) Undistributed Earnings from Subsidiary Companies	458,568	-2,245,730
18	Other (provide details in footnote):	98,672,790	34,578,068
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	996,177,167	1,087,766,479
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,027,696,687	-978,679,537
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-17,190,558	-15,027,424
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,010,506,129	-963,652,113
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	156,046	450,253
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		2,000,000
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	1,941,409	-208,792
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,008,408,674	-961,410,652
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	594,750,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	49,834,000	83,700,000
67	Other (provide details in footnote):	9,107,370	15,829,395
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	653,691,370	99,529,395
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-450,000,000	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-173,716,006	-227,784,248
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	29,975,364	-128,254,853
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	17,743,857	-1,899,026
87			
88	Cash and Cash Equivalents at Beginning of Period	35,033,123	36,932,149
89			
90	Cash and Cash Equivalents at End of period	52,776,980	35,033,123

Schedule Page: 120 Line No.: 18 Column: b

Other components of operating cash flows	**Q4 2018**	**Q4 2017**
Other Long-Term Assets	$ (3,537,618)	$ (5,382,357)
Other Long-Term Liabilities	$ 54,210,428	$(118,200,673)
Conservation Amortization	$ 111,713,736	$ 121,216,220
Pension Funding	$ (18,000,000)	$ (18,000,000)
Net Unrealized (Gain) Loss on Derivative Transactions	$ (41,661,501)	$ 30,790,455
Prepayments & Other	$ (4,052,255)	$ 24,154,423
	$ 98,672,790	$ 34,578,068

Schedule Page: 120 Line No.: 53 Column: b

Other components of investing cash flows	**Q4 2018**	**Q4 2017**
Life Insurance Premiums	1,955,409	1,248,883
Asset retirement	0	(1,363,195)
Renewable energy credits	(14,000)	(94,480)
	$ 1,941,409	$ (208,792)

Schedule Page: 120 Line No.: 67 Column: b

Other components of financing cash flows	**Q4 2018**	**Q4 2017**
Debt issue (redemption costs) costs	$ (6,389,086)	$ 27,276
Refundable cash received for customer construction projects	16,137,161.00	16,213,011.00
Lease Financing Activity	(640,705)	(410,892)
	$ 9,107,370	$ 15,829,395

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation

These financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than generally accepted accounting principles. As a result, the presentation of these financial statements differs from generally accepted accounting principles. Certain disclosures which are required by generally accepted accounting principles and not required by FERC have been excluded from these financial statements.

As required by FERC, Puget Sound Energy, Inc. (PSE) classifies certain items in its Form 1 Balance Sheet (primarily the classification of the components of accumulated deferred income taxes, non-legal asset retirement obligations, certain miscellaneous current and accrued liabilities, maturities of long-term debt, deferred debits and deferred credits) in a manner different than that required by generally accepted accounting principles.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

PSE is a public utility incorporated in the state of Washington that furnishes electric and natural gas services in a territory covering approximately 6,000 square miles, primarily in the Puget Sound region.

Utility Plant

PSE capitalizes, at original cost, additions to utility plant, including renewals and betterments. Costs include indirect costs such as engineering, supervision, certain taxes, pension and other employee benefits and an allowance for funds used during construction (AFUDC). Replacements of minor items of property are included in maintenance expense. When the utility plant is retired and removed from service, the original cost of the property is charged to accumulated depreciation and costs associated with removal of the property, less salvage, are charged to the cost of removal regulatory liability.

Planned Major Maintenance

Planned major maintenance is an activity that typically occurs when PSE overhauls or substantially upgrades various systems and equipment on a scheduled basis. Costs related to planned major maintenance are deferred and amortized to the next scheduled major maintenance. This accounting method also follows the Washington Utilities and Transportation Commission (Washington Commission) regulatory treatment related to these generating facilities.

Other Property and Investments

The costs of other property and investments (i.e., non-utility) are stated at historical cost. Expenditures for refurbishment and improvements that significantly add to productive capacity or extend useful life of an asset are capitalized. Replacements of minor items are expensed on a current basis. Gains and losses on assets sold or retired, which were previously recorded in utility plant, are apportioned between regulatory assets/liabilities and earnings. However, gains and losses on assets sold or retired, not previously recorded in utility plant, are reflected in earnings.

Depreciation and Amortization

The Company provides for depreciation and amortization on a straight-line basis. Amortization is recorded for intangibles such as regulatory assets and liabilities, computer software and franchises. The annual depreciation provision stated as a percent of a depreciable electric utility plant was 3.3%, 2.8%, and 2.8% in 2018, 2017 and 2016, respectively; depreciable natural gas utility plant was 2.8%, 3.4%, and 3.4% in 2018, 2017 and 2016, respectively; and depreciable common utility plant was 7.1%, 8.3% and 9.7% in 2018, 2017 and 2016, respectively. The cost of removal is collected from PSE's customers through depreciation expense and any excess is recorded as a regulatory liability.

Tacoma LNG Facility

The Tacoma LNG facility is intended to provide peak-shaving services to PSE's natural gas customers. By storing surplus natural gas, PSE is able to meet the requirements of peak consumption. LNG will also provide fuel to transportation customers, particularly in the marine market. On January 24, 2018, the Puget Sound Clean Air Agency determined a Supplemental Environmental Impact Statement is necessary in order to rule on the air quality permit for the facility. As a result of requiring an SEIS, the Company's construction schedule may be impacted depending on the Puget Sound Clean Air Agency's timing and decision on the air quality permit.

If delayed, the construction schedule and costs may be adversely impacted. Pursuant to an order by the Washington Commission, PSE will be allocated approximately 43.0% of common capital and operating costs, consistent with the regulated portion of the Tacoma LNG facility. For PSE, construction work in progress of $130.8 million related to PSE's portion of the Tacoma LNG facility is reported in the "Utility plant - Natural gas plant" financial statement line item, as PSE is a regulated entity.

Cash and Cash Equivalents

Cash and cash equivalents consist of demand bank deposits and short-term highly liquid investments with original maturities of three months or less at the time of purchase. The carrying amounts of cash and cash equivalents are reported at cost and approximate fair value, due to the short-term maturity.

Materials and Supplies

Materials and supplies are used primarily in the operation and maintenance of electric and natural gas distribution and transmission systems as well as spare parts for combustion turbines used for the generation of electricity. The Company records these items at weighted-average cost.

Fuel and Natural Gas Inventory

Fuel and natural gas inventory is used in the generation of electricity and for future sales to the Company's natural gas customers. Fuel inventory consists of coal, diesel and natural gas used for generation. Natural gas inventory consists of natural gas and LNG held in storage for future sales. The Company records these items at the lower of cost or net realizable value method.

Regulatory Assets and Liabilities

PSE accounts for its regulated operations in accordance with ASC 980, "Regulated Operations" (ASC 980). ASC 980 requires PSE to defer certain costs or losses that would otherwise be charged to expense, if it is probable that future rates will permit recovery of such costs. It similarly requires deferral of revenues or gains that are expected to be returned to customers in the future. Accounting under ASC 980 is appropriate as long as rates are established by or subject to approval by independent third-party regulators; rates are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers. In most cases, PSE classifies regulatory assets and liabilities as long-term when amortization periods extend longer than one year. For further details regarding regulatory assets and liabilities, see Note 4, "Regulation and Rates".

Allowance for Funds Used During Construction

AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. The amount of AFUDC recorded in each accounting period varies depending primarily upon the level of construction work in progress and the AFUDC rate used. AFUDC is capitalized as a part of the cost of utility plant; the AFUDC debt portion is credited to interest expense, while the AFUDC equity portion is credited to other income. Cash inflow related to AFUDC does not occur until these charges are reflected in rates. The current AFUDC rate authorized by the Washington Commission for natural gas and electric utility plant additions through December 18, 2017 was 7.77%. Effective December 19, 2017 with the Washington Commission order, the new AFUDC rate authorized is 7.60%.

The Washington Commission authorized the Company to calculate AFUDC using its allowed rate of return. To the extent amounts calculated using this rate exceed the AFUDC calculated rate using the Federal Energy Regulatory Commission (FERC) formula, PSE capitalizes the excess as a deferred asset, crediting other income. The deferred asset is being amortized over the average useful life of PSE's non-project electric utility plant which is approximately 30 years.

Revenue Recognition

Operating utility revenue is recognized when the basis of services is rendered, which includes estimated unbilled revenue. Revenue from retail sales is billed based on tariff rates approved by the Washington Commission. PSE's estimate of unbilled revenue is based on a calculation using meter readings from its automated meter reading (AMR) system. The estimate calculates unbilled usage at the end of each month as the difference between the customer meter readings on the last day of the month and the last customer meter readings billed. The unbilled usage is then priced at published rates for each tariff rate schedule to estimate the unbilled revenues by customer.

PSE collected Washington State excise taxes (which are a component of general retail customer rates) and municipal taxes totaling \$239.3 million, \$257.1 million and \$235.3 million for 2018, 2017 and 2016, respectively. The Company reports the collection of such taxes on a gross basis in operation revenue and as expense in taxes other than income taxes in the accompanying consolidated statements of income.

PSE's electric and natural gas operations contain a revenue decoupling mechanism under which PSE's actual energy delivery revenues related to electric transmission and distribution, natural gas operations and general administrative costs are compared with authorized revenues allowed under the mechanism. The mechanism mitigates volatility in revenue and gross margin erosion due to weather and energy efficiency. Any differences in revenue are deferred to a regulatory asset for under recovery or regulatory liability for over recovery under alternative revenue recognition standard. Revenue is recognized under this program when deemed collectible within 24 months based on alternative revenue recognition guidance. Decoupled rate increases are effective May 1 of each year subject to a 3.0% cap of total revenue for decoupled rate schedules. Any excess revenue above 3.0% will be included in the following year's decoupled rate. The Company will be able to recognize revenue below the 3.0% cap of total revenue for decoupled rate schedules. For revenue deferrals exceeding the annual 3.0% rate cap of total revenue for decoupled rate schedules, the Company will assess the excess amount to determine its ability to be collected within 24 months. On December 5, 2017, the Washington Commission approved PSE's request within the 2017 general rate case (GRC) to extend the decoupling mechanism with some changes to the methodology that took effect on December 19, 2017. The rate test which limits the amount of revenues PSE can collect in its annual filings increased from 3.0% to 5.0% for natural gas customers but will remain at 3.0% for electric customers. The Company will not record any decoupling revenue that is expected to take longer than 24 months to collect following the end of the annual period in which the revenues would have otherwise been recognized. Once determined to be collectible within 24 months, any previously non-recognized amounts will be recognized. Revenues associated with energy costs under the power cost adjustment (PCA) mechanism and purchased gas adjustment (PGA) mechanism are excluded from the decoupling mechanism.

Allowance for Doubtful Accounts

Allowance for doubtful accounts are provided for electric and natural gas customer accounts based upon a historical experience rate of write-offs of energy accounts receivable along with information on future economic outlook. The allowance account is adjusted monthly for this experience rate. The allowance account is maintained until either receipt of payment or the likelihood of collection is considered remote at which time the allowance account and corresponding receivable balance are written off. The Company's balance for allowance for doubtful accounts at December 31, 2018 and 2017 was $8.4 million and $8.9 million, respectively.

Self-Insurance

PSE is self-insured for storm damage and certain environmental contamination associated with current operations occurring on PSE-owned property. In addition, PSE is required to meet a deductible for a portion of the risk associated with comprehensive liability, workers' compensation claims and catastrophic property losses other than those which are storm related. Under the December 5, 2017 Washington Commission order regarding PSE's GRC, the cumulative annual cost threshold for deferral of storms under the mechanism increased from $8.0 million to $10.0 million effective January 1, 2018. Additionally, costs may only be deferred if the outage meets the Institute of Electrical and Electronics Engineers (IEEE) outage criteria for system average interruption duration index.

Federal Income Taxes

For presentation in PSE's separate financial statements, income taxes are allocated to the subsidiaries on the basis of separate company computations of tax, modified by allocating certain consolidated group limitations which are attributed to the separate company.

Natural Gas Off-System Sales and Capacity Release

PSE contracts for firm natural gas supplies and holds firm transportation and storage capacity sufficient to meet the expected peak winter demand for natural gas by its firm customers. Due to the variability in weather, winter peaking consumption of natural gas by most of its customers and other factors, PSE holds contractual rights to natural gas supplies and transportation and storage capacity in excess of its average annual requirements to serve firm customers on its distribution system. For much of the year, there is excess capacity available for third-party natural gas sales, exchanges and capacity releases. PSE sells excess natural gas supplies, enters into natural gas supply exchanges with third parties outside of its distribution area and releases to third parties excess interstate natural gas pipeline capacity and natural gas storage rights on a short-term basis to mitigate the costs of firm transportation and storage capacity for its core natural gas customers. The proceeds from such activities, net of transactional costs, are accounted for as reductions in the cost of purchased natural gas and passed on to customers through the PGA mechanism, with no direct impact on net income. As a result, PSE nets the sales revenue and associated cost of sales for these transactions in purchased natural gas.

As part of the Company's electric operations, PSE purchases natural gas for its gas-fired generation facilities. The projected volume of natural gas for power is relative to the price of natural gas. Based on the market prices for natural gas, PSE may use the natural gas it has already purchased to generate power or PSE may sell the already purchased natural gas. The net proceeds from selling natural gas, previously purchased for power generation, are accounted for in electric operating revenue and are included in the PCA mechanism.

Accounting for Derivatives

ASC 815 requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value unless the contracts qualify for an exception. PSE enters into derivative contracts to manage its energy resource portfolio and interest rate exposure including forward physical and financial contracts and swaps. Some of PSE's physical electric supply contracts qualify for the normal purchase normal sale (NPNS) exception to derivative accounting rules. PSE may enter into financial fixed price contracts to economically hedge the variability of certain index-based contracts. Those contracts that do not meet the NPNS exception are marked-to-market to current earnings in the statements of income, subject to deferral under ASC 980, for natural gas related derivatives due to the PGA mechanism. For additional information, see Note 10"Accounting for Derivative Instruments and Hedging Activities".

Fair Value Measurements of Derivatives

ASC 820, "Fair Value Measurements and Disclosures" (ASC 820), defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). As permitted under ASC 820, the Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing the majority of its assets and liabilities measured and reported at fair value. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company primarily applies the market approach for recurring fair value measurements as it believes that the approach is used by market participants for these types of assets and liabilities. Accordingly, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The Company values derivative instruments based on daily quoted prices from an independent external pricing service. When external quoted market prices are not available for derivative contracts, the Company uses a valuation model that uses volatility assumptions relating to future energy prices based on specific energy markets and utilizes externally available forward market price curves. All derivative instruments are sensitive to market price fluctuations that can occur on a daily basis. For additional information, see Note 11, "Fair Value Measurements".

Debt Related Costs

Debt premiums, discounts, expenses and amounts received or incurred to settle hedges are amortized over the life of the related debt for the Company. The premiums and costs associated with reacquired debt are deferred and amortized over the life of the related new issuance, in accordance with ratemaking treatment for PSE and presented net of long-term liabilities on the balance sheet.

(2) New Accounting Pronouncements

Recently Adopted Accounting Guidance

Stranded Tax Effects in AOCI

In February 2018, the FASB issued ASU 2018-02, "Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income". The amendments in this update allow reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the TCJA and will improve the usefulness of information reported to financial statement users.

These amendments are effective for fiscal years beginning after December 15, 2018, including interim periods within those years. Early adoption is permitted, including adoption in any interim period for reporting periods for which financial statements have not yet been issued. The Company early adopted ASU 2018-02 as of January 1, 2018 and reclassified accumulated other comprehensive income to retained earnings, resulting in a $27.3 million increase for PSE, comprised of $26.2 million related to pension and post-retirement plans and $1.1 million related to interest rate swaps.

The Federal Energy Regulatory Commission's accounting regulations do not specifically provide for adjustments to retained earnings resulting from changes in accounting guidance. Docket No. AC19-19-000, submitted on behalf of PSE, proposed to reclassify stranded tax amounts from Account 219, Accumulated Other Comprehensive Income, to Account 439 for the reduction in corporate tax rate from 35 percent to 21 percent enacted by Congress in the Tax Cuts and Jobs Act. In response, the Commission has allowed the use of Account 439 to record a cumulative-effect adjustment to retained earnings to implement ASU 2018-02.

Statement of Cash Flows

In August 2016, the FASB issued ASU 2016-15, "*Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments*". The amendments in ASU 2016-15 provide guidance for eight specific cash flow issues that include (i) debt prepayment or debt extinguishment costs, (ii) settlement of zero-coupon debt instruments, (iii) contingent consideration payments made after a business combination, (iv) proceeds from the settlement of insurance claims, (v) proceeds from the settlement of corporate-owned life insurance policies, including bank-owned life insurance policies, (vi) distribution received from equity method investees, (vii) beneficial interest in securitization transactions, and (viii) separately identifiable cash flows and application of the predominance principle.

This update is effective for financial statements issued for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted for all entities upon issuance. The amendments in this update should be applied using a retrospective transition method to each period presented. The Company adopted ASU 2016-15 as of January 1, 2018, with the standard only impacting the classification of debt extinguishment costs as financing outflows.

In November 2016, the FASB issued ASU 2016-18, "*Statement of Cash Flows (Topic 230): Restricted Cash*". The amendments in this update require that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. The new standard is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The Company adopted ASU 2016-18 as of January 1, 2018, by moving the presentation of restricted cash in the statement of cash flows to net cash flows of total cash, cash equivalents, and restricted cash. Amounts included in restricted cash primarily represent funds required to be set aside for contractual obligations related to transmission and generation facilities.

The following tables provide a reconciliation of cash, cash equivalents and restricted cash reported within the statements of cash flows:

Puget Sound Energy	Twelve Months Ended December 31,	
(Dollars in Thousands)	2018	2017
Cash and cash equivalents	$ 34,727	$ 24,969
Restricted cash	18,050	10,064
Total cash, cash equivalents and restricted cash shown in the statement of cash flows	$ 52,776	$ 35,033

Revenue Recognition

In May 2014, the FASB issued ASU No. 2014-09, "*Revenue from Contracts with Customers (Topic 606)*". ASU 2014-09 and the related amendments outline a single comprehensive model for use in accounting for revenue arising from contracts with customers and supersede most current revenue recognition guidance, including industry-specific guidance. The ASU is based on the principle that an entity should recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The ASU also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts, including significant judgments and changes in judgments and assets recognized from costs incurred to fulfill a contract.

The Company implemented the standard as of January 1, 2018, using the modified retrospective method of adoption. As a result of implementation of this standard, the Company made no cumulative adjustments to revenue for contracts with customers open as of January 1, 2018. For the Twelve Months Ended December 31, the Company's revenue was 90.7% comprised of contracts with retail customers from rate-regulated sales of electricity and natural gas where revenue is recognized over time as delivered.

Accounting Standards Issued but Not Yet Adopted

Internal-Use Software

In August 2018, the FASB issued ASU 2018-15, *"Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract"*. These amendments align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software (and hosting arrangements that include an internal-use software license). The accounting for the service element of a hosting arrangement that is a service contract is not affected by these amendments.

The amendments in this update are effective for public business entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption of the amendments in this update is permitted, including adoption in any interim period, for all entities. The amendments in this update should be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. The Company will adopt this update prospectively beginning 2019 by evaluating future contracts for implementation costs incurred in hosting arrangements. The financial impact of this update has not yet been determined.

Fair Value Measurement

In August 2018, the FASB issued ASU 2018-13, *"Fair Value Measurement (Topic 820): Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement"*. The amendments in this update modify the disclosure requirements on fair value measurements in Topic 820, Fair Value Measurement, based on the concepts in the Concepts Statement, including the consideration of costs and benefits. The amendments are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. The Company is in the process of evaluating potential impacts of these amendments to Note 11, "Fair Value Measurements".

Retirement Benefits

In August 2018, the FASB issued ASU 2018-14, "*Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans*". This update modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans through added, removed, and clarified requirements of relevant disclosures.

The amendments in this update are effective for fiscal years ending after December 15, 2020, for public business entities and for fiscal years ending after December 15, 2021, for all other entities. Early adoption is permitted for all entities. The Company is in the process of evaluating potential impacts of these amendments to Note 13, "Retirement Benefits".

Lease Accounting

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)". The FASB issued this ASU to increase transparency and comparability among organizations by recognizing right-of-use (ROU) lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. To meet that objective, the FASB is amending the FASB ASC and creating Topic 842, Leases. ASU 2016-02 requires lessees to recognize the following for all leases (with the exception of short-term leases) at the commencement date: (i) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (ii) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. The income statement recognition is similar to existing lease accounting and is based on lease classification. Under the new guidance, lessor accounting is largely unchanged.

In January 2018, the FASB issued ASU 2018-01, "Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842". In connection with the FASB's transition support efforts, the amendments in this update provide an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current guidance in Topic 840. An entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 upon adoption. Land easements (also commonly referred to as rights of way) represent the right to use, access, or cross another entity's land for a specified purpose. The Company plans to elect this practical expedient, and will evaluate new and modified land easements prospectively, beginning January 1, 2019.

In July 2018, the FASB issued both ASU 2018-10 and ASU 2018-11, "Leases (Topic 842): Codification Improvements" and "Leases (Topic 842): Targeted Improvements". These ASUs provide entities with both clarification on existing guidance issued in ASU 2016-02, as well as an additional transition method to adopt the new leasing standard. Under the new transition method, the entity initially applies the new standard at the adoption date by recognizing a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, an entity's reporting for the comparative periods presented in the financial statements will continue to be in accordance with Topic 840. The Company has elected to adopt the standard using this new modified transition method.

In preparation for adoption of the standard, the Company assembled a project team that met bi-weekly to make key accounting assessments and perform pre-implementation controls related to the scoping and completeness of existing leases. Additionally, the Company implemented a new leasing system, and drafted accounting policies including discount rate, variable pricing, power purchase agreements, and election of practical expedients. In addition to the land easement practical expedient, the Company has elected the practical expedient package. The Company is continuing to evaluate discount rate assumptions using the portfolio approach.

These amendments are effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. The Company will adopt ASU 2016-02 as of January 1, 2019 and expects the adoption of the standard will result in recognition of right-of-use asset and lease liability financial statement line items that have not previously been recorded and will be material to the consolidated balance sheets. Adoption of the standard will not have a material impact on the income statement.

(3) Regulation and Rates

Regulatory Assets and Liabilities

Regulatory accounting allows PSE to defer certain costs that would otherwise be charged to expense, if it is probable that future rates will permit recovery of such costs. It similarly requires deferral of revenues or gains that are expected to be returned to customers in the future.

The net regulatory assets and liabilities at December 31, 2018 and 2017, included the following:

Puget Sound Energy (Dollars in Thousands)	Remaining Amortization Period	December 31, 2018	December 31, 2017
Storm damage costs electric	4 to 6 years	118,331	128,508
Chelan PUD contract initiation	12.8 years	90,964	98,052
Environmental remediation	(a)	76,345	81,550
Lower Snake River	18.4 years	67,021	70,975
Decoupling deferrals and interest	Less than 2 years	65,779	98,769
Baker Dam licensing operating and maintenance costs	N/A	55,607	54,817
Deferred Washington Commission AFUDC	10 years	52,029	50,301
Property tax tracker	Less than 2 years	45,621	36,517
Unamortized loss on reacquired debt	1 to 28 years	42,378	39,674
Energy conservation costs	(a)	30,701	35,538
Generation plant major maintenance, excluding Colstrip	4 to 10 years	15,027	17,216
PGA deferral of unrealized losses on derivative instruments	N/A	14,739	26,030
White River relicensing and other costs	3 years	12,966	19,502
Mint Farm ownership and operating costs	6.3 years	12,319	14,319
PGA receivable	1 year	9,922	—
Snoqualmie licensing operating and maintenance costs	N/A	7,407	7,341
Colstrip major maintenance	0.5 years	6,841	8,723
PCA mechanism	N/A	4,735	4,576
Colstrip common property	6.4 years	3,903	4,618
Ferndale	0.8 years	3,316	7,295
Electron unrecovered loss	Less than 1 year	—	3,786
Various other regulatory assets	(a)	14,583	17,382
Total PSE regulatory assets		750,534	825,489
Deferred income taxes(d)	N/A	(976,582)	(1,012,260)
Cost of removal	(b)	(424,727)	(389,579)
Treasury grants	20 years	(168,884)	(205,775)
Production tax credits	(c)	(93,616)	(93,616)
Accumulated provision for rate refunds	N/A	(34,579)	—

Decoupling ROR excess earnings		—		(18,400)	
Decoupling deferrals and interest		(13,758)		(7,896)	
Total decoupling liability	Less than 2 years		(13,758)		(26,296)
Summit purchase option buy-out	1.8 years		(2,888)		(4,463)
PGA payable	1 year		—		(16,051)
Various other regulatory liabilities	(a)		(7,428)		(10,544)
Total PSE regulatory liabilities			(1,722,462)		(1,758,584)
PSE net regulatory assets (liabilities)			$ (971,928)		$ (933,095)

____

(a) Amortization periods vary depending on timing of underlying transactions.

The balance is dependent upon the cost of removal of underlying assets and the life of utility plant.

(b) Amortization will begin once PTCs are utilized by PSE on its tax return.

For additional information, see Note 14,"Income Taxes".

If the Company determines that it no longer meets the criteria for continued application of ASC 980, the Company would be required to write-off its regulatory assets and liabilities related to those operations not meeting ASC 980 requirements. Discontinuation of ASC 980 could have a material impact on the Company's financial statements.

In accordance with guidance provided by ASC 410, “Asset Retirement and Environmental Obligations (ARO),” PSE reclassified from accumulated depreciation to a regulatory liability $424.7 million and $389.6 million in 2018 and 2017, respectively, for the cost of removal of utility plant. These amounts are collected from PSE’s customers through depreciation rates.

Expedited Rate Filing Rate Adjustment

On November 7, 2018, PSE filed an expedited rate filing (ERF) with the Washington Commission. The filing is a request to change rates associated with PSE’s delivery and fixed production costs. It does not include variable power costs, purchased gas costs or natural gas pipeline replacement program costs, which are recovered in separate mechanisms. The filing is based on historical test year costs and rate base, and follows the reporting requirements of a Commission Basis Report, as defined by the Washington Administrative Code, but is filed using end of period rate base and certain annualizing adjustments. It does not include any forward-looking or pro-forma adjustments. Included in the filing is a reduction to the overall authorized rate of return from 7.6% to 7.49% to recognize a reduction in debt costs associated with recent debt activity. PSE requested an overall increase in electric rates of $18.9 million annually, which is a 0.9% increase, and an overall increase in natural gas rates of $21.7 million annually, which is a 2.7% increase.

On January 22, 2019, all parties in the proceeding reached an agreement on settlement terms that resolve all issues in the filing. The settlement agreement was filed on January 30, 2019. The major points covered by the agreement are as follows. The agreed upon rate increases in the settlement are $21.5 million on natural gas and no rate increase on electric which would become effective March 1, 2019. Items that were not specifically identified in the settlement are deemed to offset the ARAM amounts that are discussed below to arrive at the settlement rate changes.

The settlement agreement in PSE’s pending expedited rate change filing provides for the pass back beginning March 1, 2018 of the turnaround of plant related excess deferred income taxes on the average rate assumption method (ARAM) that resulted from the Tax Cuts and Jobs Act based on 2018 amounts in the amount of $6.1 million for natural gas and $25.9 million for electric. The settlement agreement leaves the determination for the regulatory treatment of the remaining items related to the TCJA to PSE’s next

GRC:

1) excess deferred taxes for non-plant- related book/tax differences,
2) the deferred balance associated with the over-collection of income tax expense for the period January 1 through April 30, 2018 (the time period that encompasses the effective date of the TCJA through May 1, 2018, the requested effective date of the rate change); and
3) the turnaround of plant related excess deferred income taxes using the ARAM method for the period from January 2018 through February 2019, the rate effective date for the ERF.

The agreement provides that PSE may defer the depreciation expense associated with PSE's ongoing investment in its advanced metering infrastructure (AMI) investment and to defer the return on the AMI investment that was included in the test year of the filing. The agreement preserves the parties' rights to argue that both deferrals should be or should not be recovered in the Company's next GRC. The rate of return adopted in the settlement is the 7.49% included in the filing. The Washington Commission has suspended the procedural calendar in the proceeding and indicated it will not require a settlement hearing and will make their decision on whether or not to approve the settlement on the paper record in the filing. A ruling by the Washington Commission is expected in enough time to implement rates on March 1, 2019.

Washington Commission Tax Deferral Filing

The Tax Cuts and Jobs Act (TCJA) was signed into law in December 2017. As a result of this change, PSE re-measured its deferred tax balances under the new corporate tax rate. PSE filed an accounting petition on December 29, 2017 requesting deferred accounting treatment for the impacts of tax reform. The requested deferral accounting treatment results in the tax rate change being captured in the deferred income tax balance with an offset to the regulatory liability for deferred income taxes. Additionally, on March 30, 2018, PSE filed for a rate change for electric and natural gas customers associated with TCJA to reflect the decrease in the federal corporate income tax rate from 35.0% to 21.0%. The overall impact of the rate change, based on the annual period from May 2018 through April 2019, is a revenue decrease of $72.9 million, or 3.4% for electric and $23.6 million, or 2.7% for natural gas.

The March 30, 2018, rate change filing did not address excess deferred taxes or the deferred balance associated with the over-collection of income tax expense of $34.6 million for the period January 1 through April 30, 2018 (the time period that encompasses the effective date of the TCJA through May 1, 2018, the effective date of the rate change). The $34.6 million tax over-collection decreased PSE's revenue and increased the regulatory liability for a refund to customers.

As a result of the ERF settlement, the excess deferred taxes associated with non-plant-related book/tax differences, the deferred balance associated with the over-collection of income tax expense and the treatment of the excess deferred taxes associated with plant related book/tax differences from January 1, 2018 through February 28, 2019 will be addressed in PSE's accounting petition in its next GRC.

General Rate Case Filing

In January 2017, PSE filed its GRC with the Washington Commission. The GRC filing included a required plan to address Colstrip Units 1 and 2 closures, requested that electric energy supply fixed costs be included in PSE's decoupling mechanism, and contained requests for two new mechanisms to address regulatory lag. The Washington Commission entered a final order accepting the multi-party settlement agreement and determined the contested issues in the case on December 5, 2017, and new rates became effective December 19, 2017. The settlement agreement provided for a weighted cost of capital of 7.6%, or 6.55% after-tax, and a capital structure of 48.5% in common equity with a return on equity of 9.5%. The settlement also resulted in a combined electric tariff change that resulted in a net increase of $20.2 million, or 0.9%, annually, and a combined natural gas tariff change that resulted in a net decrease of $35.5 million, or 3.8%, annually.

The GRC also re-purposed the benefit of PTCs and hydro-related treasury grants to fund and recover decommissioning and remediation costs for Colstrip Units 1 and 2. As the Company monetizes PTCs on its filed tax returns, the regulatory liability is transferred to a reserve for Colstrip Units 1 and 2 decommissioning and remediation costs.

Decoupling Filings

While fluctuations in weather conditions will continue to affect PSE's billed revenue and energy supply expenses from month to month, PSE's decoupling mechanisms assist in mitigating the impact of weather on operating revenue and net income. Since July 2013, the Washington Commission has allowed PSE to record a monthly adjustment to its electric and natural gas operating revenues related to electric transmission and distribution, natural gas operations and general administrative costs from most residential, commercial and industrial customers to mitigate the effects of abnormal weather, conservation impacts and changes in usage patterns per customer. As a result, these electric and natural gas revenues are recovered on a per customer basis regardless of actual consumption levels. PSE's energy supply costs, which are part of the PCA and PGA mechanisms, are not included in the decoupling mechanism. The revenue recorded under the decoupling mechanisms will be affected by customer growth and not actual consumption. Following each calendar year, PSE will recover from, or refund to, customers the difference between allowed decoupling revenue and the corresponding actual revenue during the following May to April time period.

On December 5, 2017, the Washington Commission approved PSE’s request within the 2017 GRC to extend the decoupling mechanism with several changes to the methodology that took effect on December 19, 2017. Electric and natural gas delivery revenues continue to be recovered on a per customer basis and electric fixed production energy costs are now decoupled and recovered on the basis of a fixed monthly amount. The allowed decoupling revenue for electric and natural gas customers will no longer increase annually each January 1 as occurred prior to December 19, 2017. Approved revenue per customer costs can only be changed in a GRC or ERF. Approved electric fixed production energy costs can also be changed in a power cost only rate case (PCORC). Other changes to the decoupling methodology approved by the Washington Commission include regrouping of electric and natural gas non-residential customers and the exclusion of certain electric schedules from the decoupling mechanism going forward. The rate test, which limits the amount of revenues PSE can collect in its annual filings, increased from 3.0% to 5.0% for natural gas customers but will remain at 3.0% for electric customers. The decoupling mechanism will be reviewed again in PSE’s first rate case filed in or after 2021, or in a separate proceeding, if appropriate. PSE’s decoupling mechanism over- and under- collections will still be collectible or refundable after this effective date even if the decoupling mechanism is not extended.

On December 31, 2018, PSE performed an analysis to determine if electric and natural gas decoupling revenue deferrals would be collected from customers within 24 months of the annual period, per ASC 980. If not, for GAAP purposes only, PSE would need to record a reserve against the decoupling revenue and regulatory asset balance. Once the reserve is probable of collection within 24 months from the end of the annual period, the reserve can be recognized as decoupling revenue. The analysis indicated that $0.8 million of electric deferred revenue will not be collected within 24 months of the annual period; therefore, an adjustment was booked to 2018 decoupling revenue. The previously unrecognized decoupling deferrals of $20.8 million at December 31, 2016, were recognized as decoupling revenue in the year ended December 31, 2017.

Storm Damage Deferral Accounting

The Washington Commission issued a GRC order that defined deferrable storm events and provided that costs in excess of the annual cost threshold may be deferred for qualifying storm damage costs that meet the modified Institute of Electrical and Electronics Engineers outage criteria for system average interruption duration index. In 2018 and 2017, PSE incurred $25.4 million and $30.4 million, respectively, in storm-related electric transmission and distribution system restoration costs, of which $15.1 million was deferred in 2018 and $21.6 million was deferred in 2017 to a regulatory asset. Under the December 5, 2017 Washington Commission order regarding PSE's GRC, the following changes to PSE's storm deferral mechanism were approved: (i) the cumulative annual cost threshold for deferral of storms under the mechanism increased from $8.0 million to $10.0 million effective January 1, 2018; and (ii) qualifying events where the total qualifying cost is less than $0.5 million will not qualify for deferral and these costs will also not count toward the $10.0 million annual cost threshold.

Environmental Remediation

The Company is subject to environmental laws and regulations by the federal, state and local authorities and is required to undertake certain environmental investigative and remedial efforts as a result of these laws and regulations. The Company has been named by the Environmental Protection Agency (EPA), the Washington State Department of Ecology and/or other third parties as potentially responsible at several contaminated sites and manufactured gas plant sites. In accordance with the guidance of ASC 450, "Contingencies," the Company reviews its estimated future obligations and will record adjustments, if any, on a quarterly basis. Management believes it is probable and reasonably estimable that the impact of the potential outcomes of disputes with certain property owners and other potentially responsible parties will result in environmental remediation costs of $42.7 million for natural gas and $8.8 million for electric. The Company believes a significant portion of its past and future environmental remediation costs are recoverable from insurance companies, from third parties or from customers under a Washington Commission order. The Company is also subject to cost-sharing agreements with third parties regarding environmental remediation projects in Seattle, Washington and Bellingham, Washington. The Company has taken the lead for both projects, and as of December 31, 2018, the Company's share of future remediation costs is estimated to be approximately $32.2 million. The Company's deferred electric environmental costs are $14.1 million and $17.6 million at December 31, 2018 and 2017, respectively, net of insurance proceeds. The Company's deferred natural gas environmental costs are $62.2 million and $63.9 million at December 31, 2018 and 2017, respectively, net of insurance proceeds. In the GRC which became effective December 19, 2017, the Company had its third party recoveries and remediation costs incurred as of September 30, 2016, net of a portion of insurance, approved for amortization and inclusion in rates.

(4) Dividend Payment Restrictions

The payment of dividends by PSE to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE's electric and natural gas mortgage indentures. At December 31, 2018, approximately $783.0 million of unrestricted retained earnings was available for the payment of dividends under the most restrictive mortgage indenture covenant.

Pursuant to the terms of the Washington Commission merger order, PSE may not declare or pay dividends if PSE's common equity ratio, calculated on a regulatory basis, is 44.0% or below except to the extent a lower equity ratio is ordered by the Washington Commission. Also, pursuant to the merger order, PSE may not declare or make any distribution unless on the date of distribution PSE's corporate credit/issuer rating is investment grade, or, if its credit ratings are below investment grade, PSE's ratio of earnings before interest, tax, depreciation and amortization (EBITDA) to interest expense for the most recently ended four fiscal quarter periods prior to such date is equal to or greater than 3.0 to 1.0. The common equity ratio, calculated on a regulatory basis, was 47.6% at December 31, 2018, and the EBITDA to interest expense was 5.6 to 1.0 for the twelve months ended December 31, 2018.

PSE's ability to pay dividends is also limited by the terms of its credit facilities, pursuant to which PSE is not permitted to pay dividends during any Event of Default (as defined in the facilities), or if the payment of dividends would result in an Event of Default, such as failure to comply with certain financial covenants.

At December 31, 2018, PSE was in compliance with all applicable covenants, including those pertaining to the payment of dividends.

(5) Utility Plant

The following table presents electric, natural gas and common utility plant classified by account:

Utility Plant (Dollars in Thousands)	Estimated Useful Life (Years)	Puget Sound Energy At December 31, 2018	Puget Sound Energy At December 31, 2017
Distribution plant	20-65	$ 7,722,024	$ 7,289,998
Production plant	12-90	4,104,963	4,081,683
Transmission plant	43-75	1,550,950	1,471,337
General plant	5-75	718,105	628,179
Intangible plant (including capitalized software)	NA	652,942	438,187
Plant acquisition adjustment	NA	282,792	282,792
Underground storage	25-60	48,874	45,288
Liquefied natural gas storage	25-60	14,498	14,498
Plant held for future use	NA	39,536	53,580
Plant not classified	NA	239,857	275,014
Capital leases, net of accumulated amortization[1]	NA	1,315	1,129
Less: accumulated provision for depreciation		(6,013,978)	(5,617,412)
Subtotal		$ 9,361,878	$ 8,964,273
Construction work in progress	NA	550,466	495,937
Net utility plant		$ 9,912,344	$ 9,460,210

1 *At December 31, 2018 and 2017, accumulated amortization of capital leases at PSE was $0.7 million.*

Jointly owned generating plant service costs are included in utility plant service cost at the Company's ownership share. The Company provides financing for its ownership interest in the jointly owned utility plants. The following tables indicate the Company's percentage ownership and the extent of the Company's investment in jointly owned generating plants in service at December 31, 2018. These amounts are also included in the Utility Plant table above. The Company's share of fuel costs and operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income.

Puget Sound Energy

Jointly Owned Generating Plants (Dollars in Thousands)	Energy Source (Fuel)	Company's Ownership Share	Plant in Service at Cost	Construction Work in Progress	Accumulated Depreciation

Colstrip Units 1 & 2[1]	Coal	50.0%	$ 498,955	$ —	$ (191,323)
Colstrip Units 3 & 4	Coal	25.0%	578,008	—	(357,914)
Colstrip Units 1 – 4 Common Facilities	Coal	various	252	—	(206)
Frederickson 1	Natural Gas	49.85%	67,858	—	(14,567)
Jackson Prairie	Natural Gas Storage	33.34%	47,975	404	(21,499)
Tacoma LNG	LNG	various	—	130,756	—

Asset Retirement Obligation

The Company has recorded liabilities for steam generation sites, combustion turbine generation sites, wind generation sites, distribution and transmission poles, natural gas mains, and leased facilities where disposal is governed by ASC 410 “Asset Retirement and Environmental Obligations" (ARO).

On April 17, 2015, the U.S. Environmental Protection Agency (EPA) published a final rule, effective October 19, 2015, that regulates Coal Combustion Residuals (CCR) under the Resource Conservation and Recovery Act, Subtitle D. The CCR ruling requires the Company to perform an extensive study on the effects of coal ash on the environment and public health. The rule addresses the risks from coal ash disposal, such as leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments.

The CCR rule and two new legal agreements which include a consent decree with the Sierra Club and a settlement agreement with the Sierra Club and the National Wildlife Federation in 2016 make significant changes to the Company’s Colstrip operations and those changes were reviewed by the Company and the plant operator in 2015 and 2016. PSE had previously recognized a legal obligation in 2003 under EPA rules to dispose of coal ash material at Colstrip.

The actual ARO costs related to the CCR rule requirements may vary substantially from the estimates used to record the increased obligation due to uncertainty about the compliance strategies that will be used and the preliminary nature of available data used to estimate costs. We will continue to gather additional data and coordinate with the plant operator to make decisions about compliance strategies and the timing of closure activities. As additional information becomes available, the Company will update the ARO obligation for these changes, which could be material.

For the twelve months ended December 31, 2018 and 2017, the Company reviewed the estimated remediation costs at Colstrip and reduced the Colstrip ARO liability by $11.0 million and $5.5 million for Colstrip Units 1 and 2 and $1.8 million and $12.7 million for Colstrip Units 3 and 4, respectively. The 2018 reductions to the Colstrip ARO liability are primarily based on the plant site remedy report approved by the Montana Department of Environmental Quality. For the twelve months ended December 31, 2018 and 2017, the Company also recorded the Colstrip relief of liability of $4.8 million and $3.8 million, respectively. In addition, the Company recorded Tacoma LNG facility ARO liability of $2.7 million for PSE as of December 31, 2017.

The following table describes the changes to the Company’s ARO for the year ended December 31, 2018:

Puget Sound Energy	At December 31,	
(Dollars in Thousands)	2018	2017
Asset retirement obligation at beginning of the period	$ 188,934	$ 200,345
New asset retirement obligation recognized in the period	501	1,454
Relief of liability	(4,750)	(3,841)
Revisions in estimated cash flows	(9,876)	(14,549)
Accretion expense	5,680	5,525

Asset retirement obligation at end of period[1]	$ 180,489	$ 188,934

The Company has identified the following obligations, as defined by ASC 410, "ARO," which were not recognized because the liability for these assets cannot be reasonably estimated at December 31, 2018:

- A legal obligation under Federal Dangerous Waste Regulations to dispose of asbestos-containing material in facilities that are not scheduled for remodeling, demolition or sales. The disposal cost related to these facilities could not be measured since the retirement date is indeterminable; therefore, the liability cannot be reasonably estimated;
- An obligation under Washington state law to decommission the wells at the Jackson Prairie natural gas storage facility upon termination of the project. Since the project is expected to continue as long as the Northwest pipeline continues to operate, the liability cannot be reasonably estimated;
- An obligation to pay its share of decommissioning costs at the end of the functional life of the major transmission lines. The major transmission lines are expected to be used indefinitely; therefore, the liability cannot be reasonably estimated;
- A legal obligation under Washington state environmental laws to remove and properly dispose of certain under and above ground fuel storage tanks. The disposal costs related to under and above ground storage tanks could not be measured since the retirement date is indeterminable; therefore, the liability cannot be reasonably estimated;
- An obligation to pay decommissioning costs at the end of utility service franchise agreements to restore the surface of the franchise area. The decommissioning costs related to facilities at the franchise area could not be measured since the decommissioning date is indeterminable; therefore, the liability cannot be reasonably estimated; and
- A potential legal obligation may arise upon the expiration of an existing FERC hydropower license if FERC orders the project to be decommissioned, although PSE contends that FERC does not have such authority. Given the value of ongoing generation, flood control and other benefits provided by these projects, PSE believes that the potential for decommissioning is remote and cannot be reasonably estimated.

(6) Long-Term Debt

The following table presents outstanding long-term debt principal amounts and due dates as of 2018 and 2017:

(Dollars in Thousands)			At December 31,	
Series	Type	Due	2018	2017
Puget Sound Energy:				
6.740%	Senior Secured Note[1]	2018	$ —	$ 200,000
5.500%	Promissory Note	2020	2,412	2,412
7.150%	First Mortgage Bond	2025	15,000	15,000
7.200%	First Mortgage Bond	2025	2,000	2,000
7.020%	Senior Secured Note	2027	300,000	300,000
7.000%	Senior Secured Note	2029	100,000	100,000
3.900%	Pollution Control Bond	2031	138,460	138,460
4.000%	Pollution Control Bond	2031	23,400	23,400
5.483%	Senior Secured Note	2035	250,000	250,000
6.724%	Senior Secured Note	2036	250,000	250,000

6.274%	Senior Secured Note	2037	300,000	300,000
5.757%	Senior Secured Note	2039	350,000	350,000
5.795%	Senior Secured Note	2040	325,000	325,000
5.764%	Senior Secured Note	2040	250,000	250,000
4.434%	Senior Secured Note	2041	250,000	250,000
5.638%	Senior Secured Note	2041	300,000	300,000
4.300%	Senior Secured Note	2045	425,000	425,000
4.223%	Senior Secured Note	2048	600,000	—
4.700%	Senior Secured Note	2051	45,000	45,000
6.974%	Junior Subordinated Note	2067	—	250,000
*	Debt discount, issuance cost and other	*	(31,412)	(26,361)
Total PSE long-term debt			3,894,860	3,749,911

* *Not Applicable.*

1 *6.74% Senior Secured Note in the amount of $200.0 million was classified on the Balance Sheet as a current maturity of long-term debt as of June 15, 2017.*

PSE's senior secured notes will cease to be secured by the pledged first mortgage bonds on the date that all of the first mortgage bonds issued and outstanding under the electric or natural gas utility mortgage indenture have been retired. As of December 31, 2018, the latest maturity date of the first mortgage bonds, other than pledged first mortgage bonds, is December 22, 2025.

Puget Sound Energy Long-Term Debt

PSE has in effect a shelf registration statement ("the existing shelf") under which it may issue, as of the date of this report, up to $200.0 million aggregate principal amount of senior notes secured by first mortgage bonds. The existing shelf will expire in November 2019.

Substantially all utility properties owned by PSE are subject to the lien of the Company’s electric and natural gas mortgage indentures. To issue additional first mortgage bonds under these indentures, PSE’s earnings available for interest must exceed certain minimums as defined in the indentures. At December 31, 2018, the earnings available for interest exceeded the required amount.

On March 5, 2018, PSE commenced a tender offer and related consent solicitation to purchase any and all of the outstanding $250.0 million 6.974% Series A Enhanced Junior Subordinated Notes due June 1, 2067. Holders of the notes received $1,005 per $1,000 principal amount of notes plus accrued and unpaid interest for notes tendered and accepted by the early tender payment deadline of March 16, 2018. Holders of notes tendered after the early tender payment deadline, but prior to the tender offer expiration on April 2, 2018 were to receive the tender offer consideration of $975 per $1,000 of principal amount of the notes plus accrued but unpaid interest. A total of $193.4 million in principal amount of notes were tendered by the early payment deadline and no notes were tendered after the early payment deadline. On March 20, 2018, $194.9 million was paid to the holders of the tendered notes. This amount included the principal, early tender consideration and accrued interest up to, but not including March 20, 2018.

Concurrently with the tender offer, PSE solicited consents from a majority (in principal amount) of the holders of PSE’s 6.274% Senior Notes due March 15, 2037 to terminate the replacement capital covenant granted to the holders of those notes. The termination of the covenant was necessary because it included restrictions related to repurchases, redemptions and repayments of the 6.974% Series A Enhanced Junior Subordinated Notes. PSE received consents from holders of 87.7% of the 6.274% Senior Notes and paid a consent fee totaling $2.6 million to those holders on March 19, 2018.

On March 28, 2018, PSE issued a notice of redemption, effective April 27, 2018, for the remaining $56.6 million principal amount of the 6.974% Series A Enhanced Junior Subordinated Notes. The notes were redeemed at a price equal to 100% of their principal amount plus accrued and unpaid interest up to, but excluding the redemption date.

On June 4, 2018, PSE issued $600.0 million of 30-year Senior Notes under its senior note indenture at an interest rate of 4.223% with a maturity date of June 15, 2048. The proceeds from the issuance were used to pay the principal and accrued interest on the Company's $200.0 million Secured Notes that matured on June 15, 2018, outstanding commercial paper borrowings of $348.0 million and other general corporate expenses.

Long-Term Debt Maturities

The principal amounts of long-term debt maturities for the next five years and thereafter are as follows:

(Dollars in Thousands)	2019	2020	2021	2022	2023	Thereafter	Total
Maturities of:							
PSE	$ —	$ 2,412	$ —	$ —	$ —	$ 3,923,860	$ 3,926,272
Total long-term debt	$ —	$ 2,412	$ 0	$ 0	$ —	$ 3,923,860	$ 3,926,272

(7) Liquidity Facilities and Other Financing Arrangements

As of December 31, 2018 and 2017, PSE had $379.3 million and $329.5 million in short-term debt outstanding, respectively. PSE's weighted-average interest rate on short-term debt, including borrowing rate, commitment fees and the amortization of debt issuance costs, during 2018 and 2017 was 3.4% and 3.5%, respectively. As of December 31, 2018, PSE had several committed credit facilities that are described below.

Puget Sound Energy

Credit Facility

In October 2017, PSE entered into a new $800.0 million credit facility which consolidates the two previous facilities into a single, smaller facility. All other features including fees, interest rate options, letter of credit, same day swingline borrowings, financial covenant and accordion feature remain substantially the same. The credit facility includes a swingline feature allowing same day availability on borrowings up to $75.0 million. The credit facility also has an expansion feature which, upon the banks' approval, would increase the total size of the facility to $1.4 billion. The unsecured revolving credit facility matures in October 2022.

The credit agreement is syndicated among numerous lenders and contains usual and customary affirmative and negative covenants that, among other things, places limitations on PSE's ability to transact with affiliates, make asset dispositions and investments or permit liens to exist. The credit agreement also contains a financial covenant of total debt to total capitalization of 65% or less. PSE certifies its compliance with such covenants to participating banks each quarter. As of December 31, 2018, PSE was in compliance with all applicable covenant ratios.

The credit agreement provides PSE with the ability to borrow at different interest rate options. The credit agreement allows PSE to borrow at the bank's prime rate or to make floating rate advances at the London Interbank Offered Rate (LIBOR) plus a spread that is based upon PSE's credit rating. PSE must pay a commitment fee on the unused portion of the credit facility. The spreads and the commitment fee depend on PSE's credit ratings. As of the date of this report, the spread to the LIBOR is 1.25% and the commitment fee is 0.175%.

As of December 31, 2018, no amounts were drawn and outstanding under PSE's credit facility. No letters of credit were outstanding and $379.3 million was outstanding under the commercial paper program. Outside of the credit agreement, PSE had a $3.0 million letter of credit in support of a long-term transmission contract and a $1.0 million letter of credit in support of natural gas purchases in Canada.

Demand Promissory Note

In 2006, PSE entered into a revolving credit facility with Puget Energy, in the form of a credit agreement and a demand promissory note (Note) pursuant to which PSE may borrow up to $30.0 million from Puget Energy subject to approval by Puget Energy. Under the terms of the Note, PSE pays interest on the outstanding borrowings based on the lower of the weighted-average interest rates of PSE's outstanding commercial paper interest rate or PSE's senior unsecured revolving credit facility. Absent such borrowings, interest is charged at one-month LIBOR plus 0.25%. As of December 31, 2018, there was no outstanding balance under the Note.

(8) Leases

PSE leases buildings and assets under operating leases. Certain leases contain purchase options, renewal options and escalation provisions. Payments received for the subleases of properties were immaterial for each of the years ended 2018, 2017 and 2016.

Operating lease expenses net of sublease receipts were:

(Dollars in Thousands)

At December 31, Years	Operating Lease Expense
2018	$ 34,093
2017	35,198
2016	31,786

The following table summarizes the Company's estimated future minimum lease payments for non-cancelable leases net of sublease receipts, through the terms of its existing contracts:

(Dollars in Thousands) At December 31,	Future Minimum Lease Payments	
Years	Operating	Capital
2019	$ 20,635	$ 495
2020	20,704	446
2021	20,630	311
2022	20,202	82
2023	19,223	—
Thereafter	132,889	—
Total minimum lease payments	$ 234,283	$ 1,334

(9) Accounting for Derivative Instruments and Hedging Activities

PSE employs various energy portfolio optimization strategies, but is not in the business of assuming risk for the purpose of realizing speculative trading revenue. The nature of serving regulated electric customers with its portfolio of owned and contracted electric generation resources exposes PSE and its customers to some volumetric and commodity price risks within the sharing mechanism of the PCA. Therefore, wholesale market transactions and PSE's related hedging strategies are focused on reducing costs and risks where feasible, thus reducing volatility in costs in the portfolio. In order to manage its exposure to the variability in future cash flows for forecasted energy transactions, PSE utilizes a programmatic hedging strategy which extends out three years. PSE's hedging strategy includes a risk-responsive component for the core natural gas portfolio, which utilizes quantitative risk-based measures with defined objectives to balance both portfolio risk and hedge costs.

PSE's energy risk portfolio management function monitors and manages these risks using analytical models and tools. In order to manage risks effectively, PSE enters into forward physical electric and natural gas purchase and sale agreements, fixed-for-floating swap contracts, and commodity call/put options. Currently, the Company does not apply cash flow hedge accounting, and therefore records all mark-to-market gains or losses through earnings.

The Company manages its interest rate risk through the issuance of mostly fixed-rate debt with varied maturities. The Company utilizes internal cash from operations, borrowings under its commercial paper program, and its credit facilities to meet short-term funding needs. The Company may enter into swap instruments or other financial hedge instruments to manage the interest rate risk associated with these debts.

The following table presents the volumes, fair values and classification of the Company's derivative instruments recorded on the balance sheets:

Puget Sound Energy	At Year Ended December 31,					
(Dollars in Thousands)	Volumes (millions)		Assets[1]		Liabilities[2]	
	2018	2017	2018	2017	2018	2017
Electric portfolio derivatives	*	*	33,287	13,391	27,284	49,050
Natural gas derivatives (MMBtus)[3]	336.6	332.1	15,732	11,014	30,472	37,044
Total derivative contracts			$ 49,019	$ 24,405	$ 57,756	$ 86,094
Current			$ 46,507	$ 22,247	$ 46,661	$ 64,859
Long-term			2,512	2,158	11,095	21,235
Total derivative contracts			$ 49,019	$ 24,405	$ 57,756	$ 86,094

1 *Balance sheet classification: Current and Long-term Unrealized gain on derivative instruments.*

2 *Balance sheet classification: Current and Long-term Unrealized loss on derivative instruments.*

3 *All fair value adjustments on derivatives relating to the natural gas business have been deferred in accordance with ASC 980, "Regulated Operations," due to the PGA mechanism. The net derivative asset or liability and offsetting regulatory liability or asset are related to contracts used to economically hedge the cost of physical gas purchased to serve natural gas customers.*

* *Electric portfolio derivatives consist of electric generation fuel of 194.8 million One Million British Thermal Units (MMBtus) and purchased electricity of 6.6 million megawatt hours (MWhs) at December 31, 2018 and 166.8 million MMBtus and 2.9 million MWhs at December 31, 2017.*

It is the Company's policy to record all derivative transactions on a gross basis at the contract level without offsetting assets or liabilities. The Company generally enters into transactions using the following master agreements: WSPP, Inc. (WSPP) agreements, which standardize physical power contracts; International Swaps and Derivatives Association (ISDA) agreements, which standardize financial natural gas and electric contracts; and North American Energy Standards Board (NAESB) agreements, which standardize physical natural gas contracts. The Company believes that such agreements reduce credit risk exposure because such agreements provide for the netting and offsetting of monthly payments as well as the right of set-off in the event of counterparty default. The set-off provision can be used as a final settlement of accounts which extinguishes the mutual debts owed between the parties in exchange for a new net amount. For further details regarding the fair value of derivative instruments, see Note 11, "Fair Value Measurements,".

The following tables present the potential effect of netting arrangements, including rights of set-off associated with the Company's derivative assets and liabilities:

Puget Sound Energy

	At December 31, 2018					
(Dollars in Thousands)	Gross Amounts Recognized in the Statement of Financial Position [1]	Gross Amounts Offset in the Statement of Financial Position	Net of Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position		
				Commodity Contracts	Cash Collateral Received/Posted	Net Amount
Assets:						
Energy derivative contracts	$ 49,019	$ —	$ 49,019	$ (25,388)	$ —	$ 23,631
Liabilities:						
Energy derivative contracts	57,756	—	57,756	(25,388)	—	32,368

Puget Sound Energy

	At December 31, 2017					
(Dollars in Thousands)	Gross Amounts Recognized in the Statement of Financial Position [1]	Gross Amounts Offset in the Statement of Financial Position	Net of Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position		
				Commodity Contracts	Cash Collateral Received/Posted	Net Amount
Assets:						

Energy derivative contracts	$ 24,405	$ —	$ 24,405	$ (17,940)	$ —	$ 6,465
Liabilities:						
Energy derivative contracts	86,094	—	86,094	(17,940)	(353)	67,801

2 *All Derivative Contract deals are executed under ISDA, NAESB and WSPP Master Netting Agreements with Right of set-off.*

The following tables present the effect and locations of the realized and unrealized gains (losses) of the Company's derivatives recorded on the statements of income:

Puget Sound Energy

(Dollars in Thousands)	Location	2018	2017
Gas for Power Derivatives:			
Unrealized	Unrealized gain (loss) on derivative instruments, net	23,186	(32,492)
Realized	Electric generation fuel	26,222	(23,195)
Power Derivatives:			
Unrealized	Unrealized gain (loss) on derivative instruments, net	18,476	1,702
Realized	Purchased electricity	12,240	(17,873)
Total gain (loss) recognized in income on derivatives		$ 80,124	$ (71,858)

The Company is exposed to credit risk primarily through buying and selling electricity and natural gas to serve its customers. Credit risk is the potential loss resulting from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for, among other things, counterparty credit analysis, exposure measurement, and exposure monitoring and mitigation.

The Company monitors counterparties for significant swings in credit default rates, credit rating changes by external rating agencies, ownership changes or financial distress. Where deemed appropriate, the Company may request collateral or other security from its counterparties to mitigate potential credit default losses. Criteria employed in this decision include, among other things, the perceived creditworthiness of the counterparty and the expected credit exposure.

It is possible that volatility in energy commodity prices could cause the Company to have material credit risk exposure with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. However, as of December 31, 2018, approximately 95.8% of the Company's energy portfolio exposure, excluding normal purchase normal sale (NPNS) transactions, is with counterparties that are rated investment grade by rating agencies and 4.2% are either rated below investment grade or not rated by rating agencies. The Company assesses credit risk internally for counterparties that are not rated by the major rating agencies.

The Company computes credit reserves at a master agreement level by counterparty. The Company considers external credit ratings and market factors, such as credit default swaps and bond spreads, in the determination of reserves. The Company recognizes that external ratings may not always reflect how a market participant perceives a counterparty's risk of default. The Company uses both default factors published by Standard & Poor's and factors derived through analysis of market risk, which reflect the application of an industry standard recovery rate. The Company selects a default factor by counterparty at an aggregate master agreement level based on a weighted average default tenor for that counterparty's deals. The default tenor is determined by weighting the fair value and contract tenors for all deals for each counterparty to derive an average value. The default factor used is dependent upon whether the counterparty is in a net asset or a net liability position after applying the master agreement levels.

The Company applies the counterparty's default factor to compute credit reserves for counterparties that are in a net asset position. The Company calculates a non-performance risk on its derivative liabilities by using its estimated incremental borrowing rate over the risk-free rate. Credit reserves are netted against unrealized gain (loss) positions. As of December 31, 2018, the Company was in a net liability position with the majority of counterparties, so the default factors of counterparties did not have a significant impact on reserves for the period. The majority of the Company's derivative contracts are with financial institutions and other utilities operating within the Western Electricity Coordinating Council. PSE also transacts power futures contracts on the Intercontinental Exchange (ICE), and natural gas contracts on the ICE NGX exchange platform. Execution of contracts on ICE requires the daily posting of margin calls as collateral through a futures and clearing agent. As of December 31, 2018, PSE had cash posted as collateral of $6.4 million related to contracts executed on the ICE platform. Also, as of December 31, 2018, PSE has a $1.0 million letter of credit posted as collateral as a condition of transacting on the ICE NGX exchange. PSE did not trigger any collateral requirements with any of its counterparties during the twelve months ended December 31, 2018, nor were any of PSE's counterparties required to post collateral resulting from credit rating downgrades.

The following table presents the aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position and the amount of additional collateral the Company could be required to post:

Puget Sound Energy	At December 31,					
(Dollars in Thousands)	2018			2017		
Contingent Feature	Fair Value[1] Liability	Posted Collateral	Contingent Collateral	Fair Value[1] Liability	Posted Collateral	Contingent Collateral
Credit rating[2]	$ 574	$ —	$ 574	$ 3,187	$ —	$ 3,187
Requested credit for adequate assurance	18,495	—	—	37,374	—	—
Forward value of contract[3]	—	—	—	353	2,639	—
Total	$ 19,069	$ —	$ 574	$ 40,914	$ 2,639	$ 3,187

1 *Represents the derivative fair value of contracts with contingent features for counterparties in net derivative liability positions. Excludes NPNS, accounts payable and accounts receivable.*

2 *Failure by PSE to maintain an investment grade credit rating from each of the major credit rating agencies provides counterparties a contractual right to demand collateral.*

3 *Collateral requirements may vary, based on changes in the forward value of underlying transactions relative to contractually defined collateral thresholds.*

(10) Fair Value Measurements

ASC 820 established a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy categorizes the inputs into three levels with the highest priority given to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority given to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities. Equity securities that are also classified as cash equivalents are considered Level 1 if there are unadjusted quoted prices in active markets for identical assets or liabilities.

Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards and options.

Level 3 - Pricing inputs include significant inputs that have little or no observability as of the reporting date. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities measured at fair value are classified in their entirety in the appropriate fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. The Company primarily determines fair value measurements classified as Level 2 or Level 3 using a combination of the income and market valuation approaches. The process of determining the fair values is the responsibility of the derivative accounting department which reports to the Controller and Principal Accounting Officer. Inputs used to estimate the fair value of forwards, swaps and options include market-price curves, contract terms and prices, credit-risk adjustments, and discount factors. Additionally, for options, the Black-Scholes option valuation model and implied market volatility curves are used. Inputs used to estimate fair value in industry-standard models are categorized as Level 2 inputs as substantially all assumptions and inputs are observable in active markets throughout the full term of the instruments. On a daily basis, the Company obtains quoted forward prices for the electric and natural gas markets from an independent external pricing service.

The Company considers its electric and natural gas contracts as Level 2 derivative instruments as such contracts are commonly traded as over-the-counter forwards with indirectly observable price quotes. However, certain energy derivative instruments with maturity dates falling outside the range of observable price quotes are classified as Level 3 in the fair value hierarchy. Management's assessment is based on the trading activity in real-time and forward electric and natural gas markets. Each quarter, the Company confirms the validity of pricing-service quoted prices used to value Level 2 commodity contracts with the actual prices of commodity contracts entered into during the most recent quarter.

Assets and Liabilities with Estimated Fair Value

The carrying values of cash and cash equivalents, restricted cash, and short-term debt as reported on the balance sheet are reasonable estimates of their fair value due to the short-term nature of these instruments and are classified as Level 1 in the fair value hierarchy. The carrying value of other investments of $49.5 million and $48.5 million at December 31, 2018 and 2017, respectively, are included in "Other property and investments" on the balance sheet. These values are also reasonable estimates of their fair value and classified as Level 2 in the fair value hierarchy as they are valued based on market rates for similar transactions.

The fair value of the junior subordinated and long-term notes were estimated using the discounted cash flow method with U.S. Treasury yields and Company's credit spreads as inputs, interpolating to the maturity date of each issue. The carrying values and estimated fair values were as follows:

Puget Sound Energy		At December 31, 2018		At December 31, 2017	
(Dollars in Thousands)	Level	Carrying Value	Fair Value	Carrying Value	Fair Value
Liabilities:					
Junior subordinated notes	2	$ —	$ —	$ 250,000	$ 238,935
Long-term debt (fixed-rate), net of discount[1]	2	3,894,860	4,574,611	3,499,911	4,550,130
Total		$ 3,894,860	$ 4,574,611	$ 3,749,911	$ 4,789,065

.

1 *The carrying value includes debt issuances costs of $24.6 million and $24.6 million for December 31, 2018 and 2017, respectively, which are not included in fair value.*

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following tables present the Company's financial assets and liabilities by level, within the fair value hierarchy, that were accounted for at fair value on a recurring basis and the reconciliation of the changes in the fair value of Level 3 derivatives in the fair value hierarchy:

Puget Sound Energy	Fair Value At December 31, 2018			Fair Value At December 31, 2017		
(Dollars in Thousands)	Level 2	Level 3	Total	Level 2	Level 3	Total
Assets:						
Electric derivative instruments	$ 28,765	$ 4,522	$ 33,287	$ 9,866	$ 3,525	$ 13,391
Natural gas derivative instruments	12,247	3,485	15,732	6,973	4,041	11,014
Total derivative assets	$ 41,012	$ 8,007	$ 49,019	$ 16,839	$ 7,566	$ 24,405
Liabilities:						
Electric derivative instruments	24,124	3,160	27,284	46,623	2,427	49,050
Natural gas derivative instruments	28,660	1,812	30,472	34,926	2,118	37,044
Total derivative liabilities	$ 52,784	$ 4,972	$ 57,756	$ 81,549	$ 4,545	$ 86,094

Puget Sound Energy	Year Ended December 31,	
Level 3 Roll-Forward Net Asset(Liability)	2018	2017

(Dollars in Thousands)	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Balance at beginning of period	$ 1,098	$ 1,923	$ 3,021	$ 972	$ 625	$ 1,597
Changes during period						
Realized and unrealized energy derivatives:						
Included in earnings[1]	34,604	—	34,604	2,781	—	2,781
Included in regulatory assets / liabilities	—	6,075	6,075	—	6,346	6,346
Settlements[2]	(33,067)	(7,197)	(40,264)	(6,549)	(6,372)	(12,921)
Transferred into Level 3	(1,987)	—	(1,987)	523	(553)	(30)
Transferred out Level 3	714	872	1,586	3,371	1,877	5,248
Balance at end of period	$ 1,362	$ 1,673	$ 3,035	$ 1,098	$ 1,923	$ 3,021

1 *Income Statement classification: Unrealized (gain) loss on derivative instruments, net. Includes unrealized gains (losses) on derivatives still held in position as of the reporting date for electric derivatives of $1.1 million, $1.5 million and $2.0 million for the years ended December 31, 2018, 2017 and 2016, respectively.*

2 *The Company had no purchases, sales or issuances during the reported periods.*

Realized gains and losses on energy derivatives for Level 3 recurring items are included in energy costs in the Company's consolidated statements of income under purchased electricity, electric generation fuel or purchased natural gas when settled. Unrealized gains and losses on energy derivatives for Level 3 recurring items are included in net unrealized (gain) loss on derivative instruments in the Company's consolidated statements of income.

In order to determine which assets and liabilities are classified as Level 3, the Company receives market data from its independent external pricing service defining the tenor of observable market quotes. To the extent any of the Company's commodity contracts extend beyond what is considered observable as defined by its independent pricing service, the contracts are classified as Level 3. The actual tenor of what the independent pricing service defines as observable is subject to change depending on market conditions. Therefore, as the market changes, the same contract may be designated Level 3 one month and Level 2 the next, and vice versa. The changes of fair value classification into or out of Level 3 are recognized each month, and reported in the Level 3 Roll-forward table above. The Company did not have any transfers between Level 2 and Level 1 during the years ended December 31, 2018, 2017 and 2016. The Company does periodically transact at locations, or market price points, that are illiquid or for which no prices are available from the independent pricing service. In such circumstances the Company uses a more liquid price point and performs a 15-month regression against the illiquid locations to serve as a proxy for market prices. Such transactions are classified as Level 3. The Company does not use internally developed models to make adjustments to significant unobservable pricing inputs.

The only significant unobservable input into the fair value measurement of the Company's Level 3 assets and liabilities is the forward price for electric and natural gas contracts. Below are the forward price ranges for the Company's commodity contracts, as of December 31, 2018:

Puget Sound Energy	Fair Value				Range		
(Dollars in Thousands)	Assets[1]	Liabilities[1]	Valuation Technique	Unobservable Input	Low	High	Weighted Average
Electric	$4,522	$3,160	Discounted cash flow	Power Prices (per MWh)	$11.35	$66.45	$29.63

Natural gas	$3,485	$1,812	Discounted cash flow	Natural Gas Prices (per MMBtu)	$1.84	$5.80	$3.18

1 *The valuation techniques, unobservable inputs and ranges are the same for asset and liability positions.*

The significant unobservable inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. Consequently, significant increases or decreases in the forward prices of electricity or natural gas in isolation would result in a significantly higher or lower fair value for Level 3 assets and liabilities. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets. At December 31, 2018, a hypothetical 10% increase or decrease in market prices of natural gas and electricity would change the fair value of the Company's derivative portfolio, classified as Level 3 within the fair value hierarchy, by $2.6 million.

(11) Employee Investment Plans

The Company's Investment Plan is a qualified employee 401(k) plan, under which employee salary deferrals and after-tax contributions are used to purchase several different investment fund options. PSE’s contributions to the employee Investment Plan were $20.7 million, $19.2 million and $17.2 million for the years 2018, 2017 and 2016, respectively. The employee Investment Plan eligibility requirements are set forth in the plan documents.

Non-represented employees and United Association of Journeymen and Apprentices of the Plumbing and Pipefitting Industry (UA) represented employees hired before January 1, 2014, and International Brotherhood of Electrical Workers Local Union 77 (IBEW) represented employees hired before December 12, 2014, have the following company contributions:

- For employees under the Cash Balance retirement plan formula, PSE will match 100% of an employee's contribution up to 6.0% of plan compensation each paycheck, and will make an additional year-end contribution equal to 1.0% of base pay.
- For employees grandfathered under the Final Average Earning retirement plan formula, PSE will match 55.0% of an employee’s contribution up to 6.0% of plan compensation each paycheck.

Non-represented and UA-represented employees hired on or after January 1, 2014 along with IBEW-represented employees hired on or after December 12, 2014, will have access to the 401(k) plan. The two contribution sources from PSE are below:

- 401(k) Company Matching: New non-represented, UA-represented and IBEW-represented employees will receive company match each paycheck based on a new schedule: 100% match on the first 3.0% of pay contributed and 50.0% match on the next 3.0% of pay contributed. An employee who contributes 6.0% of pay will receive 4.5% of pay in company match. Company matching will be immediately vested.
- Company Contribution: New UA-represented employees will receive an annual company contribution of 4.0% of eligible pay placed in the Cash Balance retirement plan. New non-represented and IBEW-represented employees will receive an annual company contribution of 4.0% of eligible pay, placed either in the Investment Plan 401(k) plan or in PSE’s Cash Balance retirement plan. New non-represented and IBEW-represented employees will make a one-time election within 30 days of hire and direct that PSE put the 4.0% contribution either into the 401(k) plan or into an account in the Cash Balance retirement plan. The Company’s 4.0% contribution will vest after three years of service.

(12) Retirement Benefits

PSE has a defined benefit pension plan (Qualified Pension Benefits) covering a substantial majority of PSE employees. Pension benefits earned are a function of age, salary, years of service and, in the case of employees in the cash balance formula plan, the applicable annual interest crediting rates. Starting with January 1, 2014, all United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry (UA) represented employees will receive annual pay contributions of 4.0% of eligible pay each year in the cash balance formula plan of the defined benefit pension. Starting January 1, 2014, for non-represented employees, and December 12, 2014 for employees represented by the IBEW, participants will receive annual employer contributions of 4.0% of eligible pay each year in the cash balance formula of the defined benefit pension or 401k plan account. Those employees receiving contributions in the cash balance formula plan also receive interest credits, which are at least 1.0% per quarter. When an employee with a vested cash balance formula benefit leaves PSE, they will have annuity and lump sum options for distribution. PSE also maintains a non-qualified Supplemental Executive Retirement Plan (SERP) for its key senior management employees.

In addition to providing pension benefits, PSE provides legacy group health care and life insurance benefits (Other Benefits) for certain retired employees. These benefits are provided principally through an insurance company. The insurance premiums, paid primarily by retirees, are based on the benefits provided during the prior year. The following tables summarize the Company's change in benefit obligation, change in plan assets and amounts recognized in the Statements of Financial Position for the years ended December 31, 2018 and 2017:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2018	2017	2018	2017	2018	2017
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 700,481	$ 652,607	$ 55,754	$ 51,734	$ 11,454	$ 11,194
Amendments	—	—	1,446	—	—	—
Service cost	22,757	20,081	847	913	69	72
Interest cost	27,303	28,373	2,120	2,285	444	500
Actuarial loss (gain)	(29,067)	40,945	1,122	2,722	(379)	725
Benefits paid	(42,662)	(40,594)	(5,581)	(1,900)	(1,037)	(1,137)
Medicare part D subsidy received	—	—	—	—	85	100
Administrative expense	(1,169)	(931)	—	—	—	—
Benefit obligation at end of period	$ 677,643	$ 700,481	$ 55,708	$ 55,754	$ 10,636	$ 11,454

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2018	2017	2018	2017	2018	2017
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 704,360	$ 620,260	$ —	$ —	$ 7,138	$ 7,200
Actual return on plan assets	(38,379)	107,836	—	—	(395)	784
Employer contribution	18,000	18,000	5,581	1,900	254	291
Benefits paid	(42,662)	(40,594)	(5,581)	(1,900)	(1,037)	(1,137)

Administrative expense	(1,077)	(1,142)	—	—	—	—
Fair value of plan assets at end of period	$ 640,242	$ 704,360	$ —	$ —	$ 5,960	$ 7,138
Funded status at end of period	$ (37,401)	$ 3,879	$ (55,708)	$ (55,754)	$ (4,676)	$ (4,316)

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2018	2017	2018	2017	2018	2017
Amounts recognized in Statement of Financial Position consist of:						
Noncurrent assets	$ —	$ 3,879	$ —	$ —	$ —	$ —
Current liabilities	—	—	(6,249)	(5,486)	(332)	(317)
Noncurrent liabilities	(37,401)	—	(49,459)	(50,268)	(4,344)	(3,999)
Net assets (liabilities)	$ (37,401)	$ 3,879	$ (55,708)	$ (55,754)	$ (4,676)	$ (4,316)

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2018	2017	2018	2017	2018	2017
Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:						
Projected benefit obligation	$ 677,643	$ 700,481	$ 55,708	$ 55,754	$ 10,636	$ 11,454
Accumulated benefit obligation	668,469	688,908	51,031	52,681	10,557	11,367
Fair value of plan assets	640,242	704,360	—	—	5,960	7,138

The following table summarizes PSE's pension benefit amounts recognized in AOCI for the years ended December 31, 2018 and 2017:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2018	2017	2018	2017	2018	2017
Amounts recognized in Accumulated Other Comprehensive Income consist of:						
Net loss (gain)	$ 229,819	$ 185,277	$ 11,450	$ 13,134	$ (3,857)	$ (4,901)
Prior service cost (credit)	(4,659)	(6,232)	1,609	208	—	—
Total	$ 225,160	$ 179,045	$ 13,059	$ 13,342	$ (3,857)	$ (4,901)

The following table summarizes PSE's net periodic benefit cost for the years ended December 31, 2018, 2017 and 2016:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2018	2017	2018	2017	2018	2017
Components of net periodic benefit cost:						
Service cost	$ 22,757	$ 20,081	$ 847	$ 913	$ 69	$ 72
Interest cost	27,303	28,373	2,120	2,285	444	500
Expected return on plan assets	(50,240)	(47,862)	—	—	(472)	(461)
Amortization of prior service cost (credit)	(1,573)	(1,573)	44	44	—	—
Amortization of net loss (gain)	14,917	13,048	2,069	1,565	(556)	(641)
Net periodic benefit cost	$ 13,164	$ 12,067	$ 5,080	$ 4,807	$ (515)	$ (530)

The following table summarizes PSE's benefit obligations recognized in other comprehensive income (OCI) for the years ended December 31, 2018 and 2017:

Puget Sound Energy	Qualified Pension Benefit		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2018	2017	2018	2017	2018	2017
Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:						
Net loss (gain)	$ 59,460	$ (18,817)	$ 1,122	$ 2,722	$ 488	$ 452
Amortization of net (loss) gain	(14,917)	(13,048)	(2,069)	(1,565)	556	641
Settlements, mergers, sales, and closures	—	—	(737)	—	—	—
Prior service cost (credit)	—	—	1,446	—	—	—
Amortization of prior service (cost) credit	1,573	1,573	(44)	(44)	—	—
Total change in other comprehensive income for year	$ 46,116	$ (30,292)	$ (282)	$ 1,113	$ 1,044	$ 1,093

The estimated net (loss) gain and prior service cost (credit) for the pension plans that will be amortized from AOCI into net periodic benefit cost in 2019 by PSE include a $12.7 million net loss and a $1.6 million credit, respectively. The estimated net (loss) gain for the SERP that will be amortized from AOCI into net periodic benefit cost in 2019 is a net loss of $1.7 million. The estimated prior service cost (credit) for the SERP that will be amortized from AOCI into net periodic benefit cost in 2019 is a net loss of $0.3 million. The estimated net (loss) gain and prior service cost (credit) for the other postretirement plans that will be amortized from AOCI into net periodic benefit cost in 2019 is a net loss of $0.4 million. The aggregate expected contributions by the Company to fund the qualified pension plan, SERP and the other postretirement plans for the year ending December 31, 2019 are expected to be at least $18.0 million, $6.2 million and $0.3 million, respectively.

Assumptions

In accounting for pension and other benefit obligations and costs under the plans, the following weighted-average actuarial assumptions were used by the Company:

	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
Benefit Obligation Assumptions	2018	2017	2018	2017	2018	2017
Discount rate	4.40 %	4.00 %	4.40 %	4.00 %	4.40 %	4.00 %
Rate of compensation increase	4.50	4.50	4.50	4.50	4.50	4.50
Medical trend rate	—	—	—	—	7.60	6.80
Benefit Cost Assumptions						
Discount rate	4.40 %	4.50 %	4.40 %	4.50 %	4.40 %	4.50 %
Return on plan assets	7.50	7.45	—	—	7.00	6.75
Rate of compensation increase	4.50	4.50	4.50	4.50	4.50	4.50
Medical trend rate	—	—	—	—	7.60	9.50

The assumed medical inflation rate used to determine benefit obligations is 7.60% in 2019 grading down to 3.90% in 2020. A 1.0% change in the assumed medical inflation rate would have the following effects:

	2018		2017	
(Dollars in Thousands)	1% Increase	1% Decrease	1% Increase	1% Decrease
Effect on post-retirement benefit obligation	$ 19	$ (18)	$ 23	$ (22)
Effect on service and interest cost components	1	(1)	1	(1)

The Company has selected the expected return on plan assets based on a historical analysis of rates of return and the Company's investment mix, market conditions, inflation and other factors. The expected rate of return is reviewed annually based on these factors. The Company's accounting policy for calculating the market-related value of assets for the Company's retirement plan is based on a five-year smoothing of asset gains (losses) measured from the expected return on market-related assets. This is a calculated value that recognizes changes in fair value in a systematic and rational manner over five years. The same manner of calculating market-related value is used for all classes of assets, and is applied consistently from year to year.

The discount rates were determined by using market interest rate data and the weighted-average discount rate from Citigroup Pension Liability Index Curve. The Company also takes into account in determining the discount rate the expected changes in market interest rates and anticipated changes in the duration of the plan liabilities.

Plan Benefits

The expected total benefits to be paid during the next five years and the aggregate total to be paid for the five years thereafter are as follows:

(Dollars in Thousands)	2019	2020	2021	2022	2023	2024-2027

Qualified Pension total benefits	$ 43,700	$ 45,100	$ 45,900	$ 47,100	$ 48,500	$ 252,400
SERP Pension total benefits	6,249	4,993	1,887	5,378	3,678	39,400
Other Benefits total with Medicare Part D subsidy	1,112	1,094	1,064	1,038	1,008	4,410
Other Benefits total without Medicare Part D subsidy	892	863	899	872	841	3,704

Plan Assets

Plan contributions and the actuarial present value of accumulated plan benefits are prepared based on certain assumptions pertaining to interest rates, inflation rates and employee demographics, all of which are subject to change. Due to uncertainties inherent in the estimations and assumptions process, changes in these estimates and assumptions in the near term may be material to the financial statements.

The Company has a Retirement Plan Committee that establishes investment policies, objectives and strategies designed to balance expected return with a prudent level of risk. All changes to the investment policies are reviewed and approved by the Retirement Plan Committee prior to being implemented.

The Retirement Plan Committee invests trust assets with investment managers who have historically achieved above-median long-term investment performance within the risk and asset allocation limits that have been established. Interim evaluations are routinely performed with the assistance of an outside investment consultant. To obtain the desired return needed to fund the pension benefit plans, the Retirement Plan Committee has established investment allocation percentages by asset classes as follows:

	Allocation		
Asset Class	Minimum	Target	Maximum
Domestic large cap equity	25%	31%	40%
Domestic small cap equity	—	9	15
Non-U.S. equity	10	25	30
Fixed income	15	25	30
Real estate	—	—	10
Absolute return	5	10	15
Cash	—	—	5

Plan Fair Value Measurements

ASC 715, “Compensation – Retirement Benefits” (ASC 715) directs companies to provide additional disclosures about plan assets of a defined benefit pension or other postretirement plan. The objectives of the disclosures are to disclose the following: (i) how investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies; (ii) major categories of plan assets; (iii) inputs and valuation techniques used to measure the fair value of plan assets; (iv) effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period; and (v) significant concentrations of risk within plan assets.

ASC 820 allows the reporting entity, as a practical expedient, to measure the fair value of investments that do not have readily determinable fair values on the basis of the net asset value per share of the investment if the net asset value of the investment is calculated in a matter consistent with ASC 946, “Financial Services – Investment Companies”. The standard requires disclosures about the nature and risk of the investments and whether the investments are probable of being sold at amounts different from the net asset value per share.

The following table sets forth by level, within the fair value hierarchy, the qualified pension plan as of December 31, 2018 and 2017:

(Dollars in Thousands)	Recurring Fair Value Measures As of December 31, 2018			Recurring Fair Value Measures As of December 31, 2017		
	Level 1	Level 2	Total	Level 1	Level 2	Total
Assets:						
Mutual Funds	$ 103,661	$ —	$ 103,661	$ 117,796	$ —	$ 117,796
Common Stock	177,949	—	177,949	209,504	—	209,504
Government Securities	—	—	—	18,316	23,782	42,098
Corporate Bonds	—	—	—	—	34,588	34,588
Cash and cash equivalents	—	702	702	2,684	9,304	11,988
Subtotal	$ 281,610	$ 702	282,312	$ 348,300	$ 67,674	415,974
Investments measured at NAV[1]			356,586			237,427
Net (payable) receivable			1,345			50,959
Total assets			$ 640,243			$ 704,360

3 *In accordance with ASU 2015-07, "Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or Its Equivalent)", certain investments that were measured at NAV per share (or its equivalent) have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the line items presented in the statement of net assets available for benefits. Investments measured at NAV primarily consist of common/collective trust funds and two partnerships held as of December 31, 2018.*

Mesirow Institutional Multi-Strategy Fund Partnership, L.P. utilizes a combination of long and short strategies through investments in investment funds. The major strategy allocations of the investment funds include (1) Investments in debt obligations of public and private entities; typically, in financial duress, and (2) Investments in equity positions on a global basis utilizing fundamental analysis.

Grosvenor Institutional Partners Fund, L.P invests substantially all of the fund assets available in the Grosvenor Master Fund, a Cayman Islands exempted company which is sponsored, managed and has the same investment objective as the Partnership fund. In addition to the Master Fund, investments are made primarily in offshore investment funds, investment partnerships, and pooled investment vehicles; collectively referred to as Portfolio Funds, which generally implement "nontraditional" or "alternative" investment strategies.

The following table sets forth by level, within the fair value hierarchy, the Other Benefits plan assets which consist of insurance benefits for retired employees, at fair value:

(Dollars in Thousands)	Recurring Fair Value Measures As of December 31, 2018			Recurring Fair Value Measures As of December 31, 2017		
	Level 1	Level 2	Total	Level 1	Level 2	Total
Assets:						
Mutual fund[1]	$ 5,910	$ —	$ 5,910	$ 7,089	$ —	$ 7,089
Investments measured at NAV[2]			50			49
Total assets			$ 5,960			$ 7,138

4 *This is a publicly traded balanced mutual fund. The fund seeks regular income, conservation of principal, and an opportunity for long-term growth of principal and income. The fair value is determined by taking the number of shares owned by the plan, and multiplying by the market price as of December 31, 2018.*

5 *In accordance with ASU 2015-07, "Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or Its Equivalent)", certain investments that were measured at NAV per share (or its equivalent) have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the line items presented in the statement of net assets available for benefits. Investments measured at NAV consist of a common/collective trust fund as of December 31, 2018.*

(13) Income Taxes

The details of income tax (benefit) expense are as follows:

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2018	2017
Charged to operating expenses:		
Current:		
Federal	$ 19,283	$ 1,127
State	438	17
Deferred:		
Federal	30,979	210,842
State	—	—
Total income tax expense	$ 50,700	$ 211,986

The following reconciliation compares pre-tax book income at the federal statutory rate of 21.0% in 2018 and 35.0% in 2017 and 2016 to the actual income tax expense in the Statements of Income:

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2018	2017
Income taxes at the statutory rate	$ 77,251	$ 185,430
Increase (decrease):		
Production tax credit[1]	—	—
Utility plant differences[2]	(25,871)	—
Executive Compensation	4,439	—
Treasury grant amortization	(4,861)	(9,537)
Tax reform	—	36,328
Other–net	(258)	(235)
Total income tax expense	$ 50,700	$ 211,986
Effective tax rate	13.8 %	40.0 %

1 *PSE's Wild Horse wind plant earned its last PTCs in December 2016. No further PTCs are expected.*

2 *Utility plant differences include the reversal of excess deferred taxes using the average rate assumption method in the amount of $29.8 million in 2018.*

The Company's net deferred tax liability at December 31, 2018 and 2017 is composed of amounts related to the following types of temporary differences:

Puget Sound Energy	At December 31,	
(Dollars in Thousands)	2018	2017
Utility plant and equipment	$ 1,998,721	$ 2,034,328
Other, net deferred tax liabilities	25,880	86,933
Subtotal deferred tax liabilities	2,024,601	2,121,261
Net regulatory liability for income taxes	(976,582)	(1,012,260)
Production tax credit carryforward	(121,616)	(187,617)
Net other deferred tax assets	—	(51,911)
Subtotal deferred tax assets	(1,098,198)	(1,251,788)
Total net deferred tax liabilities	$ 926,403	$ 869,473

On December 22, 2017, President Trump signed into law legislation referred to as the TCJA. Substantially all of the provisions of the TCJA are effective for taxable years beginning after December 31, 2017. The TCJA includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities and includes specific provisions related to regulated public utilities including PSE. The most significant change that impacts the Company included in the TCJA is the reduction in the corporate federal income tax rate from 35.0% to 21.0% and the limitation of deductibility of executive compensation. The specific provisions related to regulated public utilities in the TCJA generally allow for the continued deductibility of interest expense, the elimination of full expensing for tax purposes of certain property acquired after December 31, 2017, and continues normalization requirements for accelerated depreciation benefits.

Under generally accepted accounting principles (US GAAP), specifically ASC Topic 740, Income Taxes, the tax effects of changes in tax laws must be recognized in the period in which the law is enacted and deferred tax assets and liabilities are to be re-measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. The change in deferred taxes is recorded as either an offset to a regulatory asset or liability and is subject to approval by the Washington Commission. Upon enactment of the TCJA, the Company re-measured its deferred tax assets and liabilities based upon the TCJA's 21.0% percent corporate federal income tax rate. The corporate tax rate change for PSE is captured in the deferred tax balance with an offset to the regulatory liability for deferred income taxes. The balance of the regulatory deferred tax account at the beginning of 2017, before tax reform, was a $71.5 million asset. As a result of tax reform, the balance is a liability of $1,012.3 million. Since PSE is in a net regulatory liability position with respect to these income tax matters, PSE netted the regulatory asset for deferred income taxes against the regulatory liability for deferred income taxes. Under the normalization requirements continued by the TCJA, $919.8 million of the net regulatory liability related to certain accelerated tax depreciation benefits is to be reversed over the remaining lives of the related assets using ARAM. The remainder of the net regulatory liability of $92.5 million is available for PSE and the Washington Commission regulatory process to determine how the amounts will be refunded to customers. PSE requested to delay the impact of tax reform in an accounting petition which was filed with the Washington Commission on December 29, 2017. For further details regarding PSE's ERF and Accounting Petition, see Note 4, "Regulation and Rates". In 2018, the Company reversed excess deferred taxes for plant-related items using ARAM in the amount of $29.8 million.

The impact of the TCJA to income tax expense as of December 31, 2017 was $36.3 million of which $3.0 million relates to deferred tax balances that are not subject to regulatory treatment. In addition, $33.3 million relates to the revaluation of the deferred tax for regulatory liability on PTC balances. The regulatory liability owed to customers for PTCs, which previously reduced revenue upon generation of the PTCs, was also revalued at the new rate of 21%. The change in the liability owed to customers for PTCs increased revenue by $51.2 million, which increased tax expense by $17.9 million, to reverse the initial deferral. The changes in the deferred tax and the liability owed to customers for PTCs had no impact on net income. The staff of the US Securities and Exchange Commission (SEC) has recognized the complexity of reflecting the impacts of the TCJA and on December 22, 2017, issued guidance in Staff Accounting Bulletin 118 (SAB 118). The guidance clarifies accounting for income taxes under ASC 740 if information is not yet available or complete and provides for up to a one year period in which to complete the required analysis and accounting (the measurement period). The Company completed the required analysis and accounting for the effects of the TCJA's enactment and did not identify any additional adjustments required.

The Company calculates its deferred tax assets and liabilities under ASC 740, “Income Taxes” (ASC 740). ASC 740 requires recording deferred tax balances, at the currently enacted tax rate, on assets and liabilities that are reported differently for income tax purposes than for financial reporting purposes. The utilization of deferred tax assets requires sufficient taxable income in future years. ASC 740 requires a valuation allowance on deferred tax assets when it is more likely than not that the deferred tax assets will not be realized. PSE’s PTC carryforwards expire from 2031 through 2036. Net operating losses generated in 2018 and thereafter have no expiration date. No valuation allowance has been provided for PTC or net operating loss carryforwards.

The Company accounts for uncertain tax positions under ASC 740, which clarifies the accounting for uncertainty in income taxes recognized in the financial statements. ASC 740 requires the use of a two-step approach for recognizing and measuring tax positions taken or expected to be taken in a tax return. First, a tax position should only be recognized when it is more likely than not, based on technical merits, that the position will be sustained upon challenge by the taxing authorities and taken by management to the court of last resort. Second, a tax position that meets the recognition threshold should be measured at the largest amount that has a greater than 50.0% likelihood of being sustained.

The following disclosure is provided pursuant to FERC Policy Statement PL 19-2-000. The Company records its accumulated deferred taxes in FERC Accounts 190, 282, and 283. Based on the Company’s estimate of the amount of deferred income taxes that would be used in setting customer rates in the future, it recorded an increase in its net regulatory liability for deferred income taxes of approximately $1,083.8 million, resulting in a regulatory liability for deferred income taxes of $1,012.3 million in FERC Account 254. At remeasurement, the Company did not change its regulated balances in its FERC 190, 282, or 283 Accounts.

Table 1: Change to ADIT balances at Remeasurement by FERC Account

Jurisdiction	**FERC 190**	**FERC 282**	**FERC 283**	**FERC 182**	**FERC 254**
FERC	$0	$0	$0	$0	$0
STATE	$0	$0	$0	$0	$0
Regulated Balance	**$0**	**$0**	**$0**	**$0**	**$0**
FAS109	$1,012.3	$0	$71.5	($71.5)	($1,012.3)
GAAP Balance	**$1,012.3**	**$0**	**$71.5**	**($71.5)**	**($1,012.3)**

The excess ADIT in each FERC account is summarized in Table 2, below.

Table 2: Excess ADIT balances at Remeasurement

Jurisdiction	**FERC 190**	**FERC 282**	**FERC 283**
FERC	$4.9	($90.7)	($3.1)
STATE	$11.2	($724.7)	($51.8)
Regulated Balance	**$16.1**	**($815.4)**	**($54.9)**

Reversal Period	Subject to future WUTC order	Average rate assumption method	Subject to future WUTC order
FERC account	FERC 410	FERC 411	FERC 411

At remeasurement, the Company had EDIT of $854.3 million of which $762.4 million was protected and $91.9 million was unprotected.

The reversal of the excess ADIT in FERC Accounts 190 and 283 will be determined by the WUTC in the Company's next general rate case. The reversal of the excess ADIT in FERC Account 282 has already begun under the average rate assumption method as provided in the WUTC's order in the Company's EFT filing. For more detail on the inclusion of excess ADIT in rates, see "Rates and Regulation" under Footnote 4 in the Company's 10K.

As of December 31, 2018 and 2017, the Company had no material unrecognized tax benefits. As a result, no interest or penalties were accrued for unrecognized tax benefits during the year.

The Company has open tax years from 2015 through 2018. The Company classifies interest as interest expense and penalties as other expense in the financial statements.

(14) Litigation

From time to time, the Company is involved in litigation or legislative rulemaking proceedings relating to its operations in the normal course of business. The following is a description of pending proceedings that are material to PSE's operations:

Colstrip

PSE has a 50% ownership interest in Colstrip Units 1 and 2, and a 25% interest in Colstrip Units 3 and 4. In March 2013, the Sierra Club and the Montana Environmental Information Center filed a Clean Air Act citizen suit against all Colstrip owners in the U.S. District Court, District of Montana. In July 2016, PSE reached a settlement with the Sierra Club to dismiss all of the Clean Air Act allegations against the Colstrip Generating Station, which was approved by the court in September 2016. As part of the settlement that was signed by all Colstrip owners, Colstrip 1 and 2 owners, PSE and Talen Energy, agreed to retire the two oldest units (Units 1 and 2) at Colstrip in eastern Montana by no later than July 1, 2022. The Washington Commission allows full recovery in rates of the net book value (NBV) at retirement and related decommissioning costs consistent with prior precedents.

Depreciation rates were updated in the GRC effective December 19, 2017, where PSE's depreciation increased for Colstrip Units 1 and 2 to recover plant costs to the expected shutdown date. The increase in depreciation caused the Colstrip Units 1 and 2 regulatory asset to be reduced to $127.6 million as of December 31, 2017. The balance of the Colstrip Units 1 and 2 regulatory asset was $130.7 million as of December 31, 2018. The full scope of decommissioning activities and costs may vary from the estimates that are available at this time. The GRC also repurposed PTCs and hydro-related treasury grants to fund and recover decommissioning and remediation costs for Colstrip Units 1 and 2. Additionally, PSE will accelerate the depreciation of Colstrip Units 3 and 4, per the terms of the GRC settlement, to December 31, 2027.

Greenwood

In March 2016, a natural gas explosion occurred in the Greenwood neighborhood of Seattle, WA, damaging multiple structures. The Washington Commission Staff completed its investigation of the incident and filed a complaint in September 2016. In March 2017, pipeline safety regulators and PSE reached a settlement in response to the complaint. As part of the agreement, PSE paid a penalty of $1.5 million in 2017, and is currently implementing a comprehensive inspection and remediation program.

Regional Haze Rule

In January 2017, the U.S. Environmental Protection Agency (EPA) published revisions to the Regional Haze Rule. Among other things, these revisions delayed new Regional Haze review from 2018 to 2021, however the end date will remain 2028. In January 2018, EPA announced that it was reconsidering certain aspects of these revisions and PSE is unable to predict the outcome.

Clean Air Act 111(d)/EPA Clean Power Plan

In June 2014, the EPA issued a proposed Clean Power Plan (CPP) rule under Section 111(d) of the Clean Air Act designed to regulate GHG emissions from existing power plants. The proposed rule includes state-specific goals and guidelines for states to develop plans for meeting these goals. The EPA published a final rule in October 2015. In March 2017, then EPA Administrator, Scott Pruitt, signed a notice of withdrawal of the proposed CPP federal plan and model trading rules and, in October 2017, the EPA proposed to repeal the CPP rule.

In August 2018, the EPA proposed the Affordable Clean Energy rule to replace the 2015 Clean Power Plan. The Affordable Clean Energy establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. Public comment closed on the proposed rule in October 2018 and PSE cannot yet predict a final outcome.

Washington Clean Air Rule

The CAR was adopted in September 2016, in Washington State and attempts to reduce greenhouse gas emissions from “covered entities” located within Washington State. Included under the new rule are large manufacturers, petroleum producers and natural gas utilities, including PSE. The CAR sets a cap on emissions associated with covered entities, which decreases over time approximately 5.0% every three years. Entities must reduce their carbon emissions, or purchase emission reduction units (ERUs), as defined under the rule, from others.

In September 2016, PSE, along with Avista Corporation, Cascade Natural Gas Corporation and NW Natural, filed a lawsuit in the U.S. District Court for the Eastern District of Washington challenging the CAR. In September 2016, the four companies filed a similar challenge to the CAR in Thurston County Superior Court. In March 2018, the Thurston County Superior Court invalidated the CAR. The Department of Ecology appealed the Superior Court decision in May 2018. As a result of the appeal, direct review to the Washington State Supreme Court was granted and oral argument will be in the end of March 2019. The federal court litigation has been held in abeyance pending resolution of the state case.

(15) Commitments and Contingencies

For the year ended December 31, 2018, approximately 13.7% of the Company’s energy output was obtained at an average cost of approximately $0.023 per Kilowatt Hour (kWh) through long-term contracts with three of the Washington Public Utility Districts (PUDs) that own hydroelectric projects on the Columbia River. The purchase of power from the Columbia River projects is on a pro rata share basis under which the Company pays a proportionate share of the annual debt service, operating and maintenance costs and other expenses associated with each project, in proportion to the contractual share of power that PSE obtains from that project. In these instances, PSE’s payments are not contingent upon the projects being operable; therefore, PSE is required to make the payments even if power is not delivered. These projects are financed substantially through debt service payments and their annual costs should not vary significantly over the term of the contracts unless additional financing is required to meet the costs of major maintenance, repairs or replacements, or license requirements. The Company’s share of the costs and the output of the projects is subject to reduction due to various withdrawal rights of the PUDs and others over the contract lives.

The Company's expenses under these PUD contracts were as follows for the years ended December 31:

(Dollars in Thousands)	2018	2017
PUD contract costs	$ 80,165	$ 73,827

As of December 31, 2018, the Company purchased portions of the power output of the PUDs' projects as set forth in the following table:

		Company's Current Share of					
(Dollars in Thousands)	Contract Expiration	Percent of Output	Megawatt Capacity	Estimated 2019 Costs	2019 Debt Service Costs	Interest included in 2019 Debt Service Costs	Debt Outstanding
Chelan County PUD:							
Rock Island Project	2031	25.0%	156	$ 29,794	$ 10,058	$ 5,053	$ 80,058
Rocky Reach Project	2031	25.0	325	30,378	5,240	2,297	36,289
Douglas County PUD:							
Wells Project[1]	2028	25.3	212	32,662	—	—	—
Grant County PUD:							
Priest Rapids Development	2052	0.6	6	2,099	1,166	1,166	13,040
Wanapum Development	2052	0.6	7	2,099	1,166	1,166	13,040
Total			706	$ 97,032	$ 17,630	$ 9,682	$ 142,427

6 *In March 2017, PSE entered a new PPA with Douglas County PUD for Wells Project output that begins upon expiration of the existing contract on August 31, 2018 and continues through September 30, 2028.*

The following table summarizes the Company's estimated payment obligations for power purchases from the Columbia River projects, contracts with other utilities, contracts with non-utilities and short term electric supply contracts. These contracts have varying terms and may include escalation and termination provisions.

(Dollars in Thousands)	2019	2020	2021	2022	2023	Thereafter	Total
Columbia River projects	$ 92,905	$ 86,691	$ 76,378	$ 85,807	$ 87,452	$ 631,283	$ 1,060,516
Other utilities	888	—	—	—	—	—	888
Non-utility contracts	216,539	255,193	264,262	264,740	269,886	1,221,204	2,491,824
Short-term electric supply contracts	117,040	4,029	—	—	—	—	121,069
Total	$ 427,372	$ 345,913	$ 340,640	$ 350,547	$ 357,338	$ 1,852,487	$ 3,674,297

Total purchased power contracts provided the Company with approximately 14.1 million, 14.5 million and 13.0 million MWhs of firm energy at a cost of approximately $508.2 million, $456.4 million and $402.5 million for the years 2018, 2017 and 2016, respectively.

Natural Gas Supply Obligations

The Company has entered into various firm supply, transportation and storage service contracts in order to ensure adequate availability of natural gas supply for its customers and generation requirements. The Company contracts for its long-term natural gas supply on a firm basis, which means the Company has a 100% daily take obligation and the supplier has a 100% daily delivery obligation to ensure service to PSE's customers and generation requirements. The transportation and storage contracts, which have remaining terms from 1 year to 26 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage. The Company incurred demand charges for 2018 for firm transportation, storage and peaking services for its natural gas customers of $119.9 million. The Company incurred demand charges in 2018 for firm transportation and storage services for the natural gas supply for its combustion turbines in the amount of $44.5 million.

The following table summarizes the Company's obligations for future natural gas supply and demand charges through the primary terms of its existing contracts. The quantified obligations are based on the FERC and NEB (National Energy Board) currently authorized rates, which are subject to change.

Natural Gas Supply and Demand Charge Obligations (Dollars in Thousands)	2019	2020	2021	2022	2023	Thereafter	Total
Natural gas supply	$ 311,601	$ 162,384	$ 157,156	$ 144,008	$ 91,851	$ —	$ 867,000
Firm transportation service	165,719	160,053	140,239	139,343	120,486	209,215	935,055
Firm storage service	8,899	7,908	3,108	1,619	504	353	22,391
Short-term natural gas supply contracts	37,589	5,734	931	—	—	—	44,254
Total	$ 523,808	$ 336,079	$ 301,434	$ 284,970	$ 212,841	$ 209,568	$1,868,700

Service Contracts

The following table summarizes the Company's estimated obligations for service contracts through the terms of its existing contracts.

Service Contract Obligations (Dollars in Thousands)	2019	2020	2021	2022	2023	Thereafter	Total
Energy production service contracts	$ 27,243	$ 27,915	$ 28,650	$ 29,345	$ 30,056	$ 124,646	$ 267,855
Automated meter reading system	45,080	44,193	44,741	45,416	46,106	142,724	368,260
Total	$ 72,323	$ 72,108	$ 73,391	$ 74,761	$ 76,162	$ 267,370	$ 636,115

Other Commitments and Contingencies

For information regarding PSE's environmental remediation obligations, see Note 4, "Regulation and Rates,"

(16) Related Party Transactions

Scott Armstrong serves on the Board of Directors of the Company and, until its acquisition by Kaiser Permanente on February 1, 2017, was the President and Chief Executive Officer of Group Health Cooperative (Group Health), a health insurance and medical care provider. Certain employees of PSE elected Group Health as their medical provider prior to its acquisition by Kaiser Permanente and as a result, PSE paid Group Health a total of $3.9 million and $23.3 million for medical coverage for the year ended December 31, 2017 and 2016. Kaiser Permanente is not considered a related party to PSE.

(17) Accumulated Other Comprehensive Income (Loss)

The following table presents the changes in the Company's (loss) AOCI by component for the years ended December 31, 2018, 2017 and 2016, respectively:

Puget Sound Energy Changes in AOCI, net of tax (Dollars in Thousands)	Net unrealized gain (loss) and prior service cost on pension plans	Net unrealized gain (loss) on energy derivative instruments	Net unrealized gain (loss) on treasury interest rate swaps	Total
Balance at December 31, 2015	$ (143,877)	$ —	$ (5,673)	$ (149,550)
Other comprehensive income (loss) before reclassifications	(5,655)	—	—	(5,655)
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	9,377	—	317	9,694
Net current-period other comprehensive income (loss)	3,722	—	317	4,039
Balance at December 31, 2016	$ (140,155)	$ —	$ (5,356)	$ (145,511)
Other comprehensive income (loss) before reclassifications	10,200	—	—	10,200
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	8,088	—	317	8,405
Net current-period other comprehensive income (loss)	18,288	—	317	18,605
Balance at December 31, 2017	$ (121,867)	$ —	$ (5,039)	$ (126,906)
Other comprehensive income (loss) before reclassifications	(48,802)	—	—	(48,802)
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	11,772	—	385	12,157
Reclassification of stranded taxes to retained earnings due to tax reform	(26,233)	—	(1,100)	(27,333)
Net current-period other comprehensive income (loss)	(63,263)	—	(715)	(63,978)
Balance at December 31, 2018	$ (185,130)	$ —	$ (5,754)	$ (190,884)

Details about the reclassifications out of AOCI (loss) for the years ended December 31, 2018, 2017 and 2016, respectively, are as follows:

Puget Sound Energy

(Dollars in Thousands)

Details about accumulated other comprehensive income (loss) components	Affected line item in the statement where net income (loss) is presented	Amount reclassified from accumulated other comprehensive income (loss) 2018	2017
Net unrealized gain (loss) and prior service cost on pension plans:			
Amortization of prior service cost	(a)	$ 1,529	$ 1,529
Amortization of net gain (loss)	(a)	(16,430)	(13,972)
	Total before tax	(14,901)	(12,443)
	Tax (expense) or benefit	3,129	4,355
	Net of tax	(11,772)	(8,088)
Net unrealized gain (loss) on energy derivative instruments:			
Commodity contracts: Electric derivatives	Purchased electricity	—	—
	Tax (expense) or benefit	—	—
	Net of Tax	—	—
Net unrealized gain (loss) on treasury interest rate swaps:			
Interest rate contracts	Interest expense	(487)	(488)
	Tax (expense) or benefit	102	171
	Net of Tax	(385)	(317)
Total reclassification for the period	Net of Tax	$ (12,157)	$ (8,405)

(a) *These AOCI components are included in the computation of net periodic pension cost, see Note 13, "Retirement Benefits,".*

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(140,154,248)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income		28,771,567		
3	Preceding Quarter/Year to Date Changes in Fair Value		(10,482,677)		
4	Total (lines 2 and 3)		18,288,890		
5	Balance of Account 219 at End of Preceding Quarter/Year		(121,865,358)		
6	Balance of Account 219 at Beginning of Current Year		(121,865,358)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income		(140,102,830)		
8	Current Quarter/Year to Date Changes in Fair Value		76,822,038		
9	Total (lines 7 and 8)		(63,280,792)		
10	Balance of Account 219 at End of Current Quarter/Year		(185,146,150)		

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(5,355,662)		(145,509,910)	[redacted]	[redacted]
2	316,968		29,088,535	[redacted]	[redacted]
3			(10,482,677)	[redacted]	[redacted]
4	316,968		18,605,858	320,054,044	338,659,902
5	(5,038,694)		(126,904,052)	[redacted]	[redacted]
6	(5,038,694)		(126,904,052)	[redacted]	[redacted]
7	(700,018)		(140,802,848)	[redacted]	[redacted]
8			76,822,038	[redacted]	[redacted]
9	(700,018)		(63,980,810)	317,163,809	253,182,999
10	(5,738,712)		(190,884,862)	[redacted]	[redacted]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	14,812,357,493	9,955,834,379
4	Property Under Capital Leases	1,314,514	
5	Plant Purchased or Sold		
6	Completed Construction not Classified	239,857,167	148,449,856
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	15,053,529,174	10,104,284,235
9	Leased to Others		
10	Held for Future Use	39,536,077	38,572,647
11	Construction Work in Progress	550,466,420	292,295,493
12	Acquisition Adjustments	282,791,675	282,791,675
13	Total Utility Plant (8 thru 12)	15,926,323,346	10,717,944,050
14	Accum Prov for Depr, Amort, & Depl	6,013,978,491	4,200,479,977
15	Net Utility Plant (13 less 14)	9,912,344,855	6,517,464,073
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	5,631,728,659	3,996,777,066
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	244,001,488	65,454,567
22	Total In Service (18 thru 21)	5,875,730,147	4,062,231,633
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	162,425	162,425
29	Amortization		
30	Total Held for Future Use (28 & 29)	162,425	162,425
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	138,085,918	138,085,918
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,013,978,490	4,200,479,976

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
3,906,672,805				949,850,309	3
				1,314,514	4
					5
69,222,473				22,184,838	6
					7
3,975,895,278				973,349,661	8
					9
611,314				352,116	10
179,328,391				78,842,536	11
					12
4,155,834,983				1,052,544,313	13
1,529,184,329				284,314,185	14
2,626,650,654				768,230,128	15
					16
					17
1,516,171,485				118,780,108	18
					19
					20
13,012,844				165,534,077	21
1,529,184,329				284,314,185	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
1,529,184,329				284,314,185	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	114,202	
3	(302) Franchises and Consents	56,751,450	423,931
4	(303) Miscellaneous Intangible Plant	82,753,968	924,601
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	139,619,620	1,348,532
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	3,795,036	
9	(311) Structures and Improvements	176,600,243	1,835,391
10	(312) Boiler Plant Equipment	709,997,739	7,717,253
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	339,256,387	7,076,586
13	(315) Accessory Electric Equipment	48,959,140	674,409
14	(316) Misc. Power Plant Equipment	15,886,632	19,978
15	(317) Asset Retirement Costs for Steam Production	100,023,099	-9,203,018
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,394,518,276	8,120,599
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	6,888,796	195,974
28	(331) Structures and Improvements	167,377,844	-1,125,475
29	(332) Reservoirs, Dams, and Waterways	351,515,904	7,494,257
30	(333) Water Wheels, Turbines, and Generators	128,252,982	1,989,131
31	(334) Accessory Electric Equipment	45,906,671	297
32	(335) Misc. Power PLant Equipment	15,773,991	302,516
33	(336) Roads, Railroads, and Bridges	5,045,058	4
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	720,761,246	8,856,704
36	D. Other Production Plant		
37	(340) Land and Land Rights	16,016,762	
38	(341) Structures and Improvements	130,108,734	1,434,765
39	(342) Fuel Holders, Products, and Accessories	25,633,030	226,498
40	(343) Prime Movers		
41	(344) Generators	1,565,629,856	16,439,215
42	(345) Accessory Electric Equipment	152,270,630	1,657,604
43	(346) Misc. Power Plant Equipment	19,043,978	1,427,878
44	(347) Asset Retirement Costs for Other Production	53,575,909	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,962,278,899	21,185,960
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,077,558,421	38,163,263

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	56,198,481	132,758
49	(352) Structures and Improvements	12,266,325	902
50	(353) Station Equipment	648,567,791	15,959,337
51	(354) Towers and Fixtures	92,203,928	
52	(355) Poles and Fixtures	369,809,207	6,999,125
53	(356) Overhead Conductors and Devices	314,055,088	19,304,196
54	(357) Underground Conduit	1,210,859	
55	(358) Underground Conductors and Devices	36,956,731	
56	(359) Roads and Trails	1,916,218	2
57	(359.1) Asset Retirement Costs for Transmission Plant	3,787,048	684,473
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,536,971,676	43,080,793
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	37,807,563	32,479
61	(361) Structures and Improvements	8,018,571	84,110
62	(362) Station Equipment	451,869,588	23,992,703
63	(363) Storage Battery Equipment	1,048,272	52,949
64	(364) Poles, Towers, and Fixtures	366,620,272	23,117,950
65	(365) Overhead Conductors and Devices	446,004,448	30,449,924
66	(366) Underground Conduit	708,531,230	35,012,960
67	(367) Underground Conductors and Devices	918,877,890	69,803,318
68	(368) Line Transformers	481,752,570	21,532,940
69	(369) Services	185,266,052	3,692,759
70	(370) Meters	153,166,099	36,741,642
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	55,229,086	2,364,305
74	(374) Asset Retirement Costs for Distribution Plant	3,412,300	-1,069,749
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,817,603,941	245,808,290
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	5,116,918	
87	(390) Structures and Improvements	66,905,363	3,565,549
88	(391) Office Furniture and Equipment	26,855,167	6,399,283
89	(392) Transportation Equipment	9,417,391	135,930
90	(393) Stores Equipment	170,597	
91	(394) Tools, Shop and Garage Equipment	11,608,461	1,624,990
92	(395) Laboratory Equipment	8,008,962	53
93	(396) Power Operated Equipment	6,222,556	278,767
94	(397) Communication Equipment	90,951,321	2,134,734
95	(398) Miscellaneous Equipment	277,392	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	225,534,128	14,139,306
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	225,534,128	14,139,306
100	TOTAL (Accounts 101 and 106)	9,797,287,786	342,540,184
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	9,797,287,786	342,540,184

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			114,202		2
72,562	1,260,603		58,363,422		3
1,141,554			82,537,015		4
1,214,116	1,260,603		141,014,639		5
					6
					7
		-61	3,794,975		8
1,281,641	582,726	1,057,511	178,794,230		9
8,368,681	5,638,021	-1,016,926	713,967,406		10
					11
4,743,609	3,643,707		345,233,071		12
1,405,765	1,266,534	-40,586	49,453,732		13
25,197	17,164		15,898,577		14
			90,820,081		15
15,824,893	11,148,152	-62	1,397,962,072		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
		229	7,084,999		27
			166,252,369		28
25,465			358,984,696		29
2,754			130,239,359		30
			45,906,968		31
			16,076,507		32
			5,045,062		33
					34
28,219		229	729,589,960		35
					36
			16,016,762		37
			131,543,499		38
			25,859,528		39
					40
6,962,393			1,575,106,678		41
709,074			153,219,160		42
		122,785	20,594,641		43
			53,575,909		44
7,671,467		122,785	1,975,916,177		45
23,524,579	11,148,152	122,952	4,103,468,209		46

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
	3,557,807	-223	59,888,823		48
64,175			12,203,052		49
5,497,094		795,330	659,825,364		50
3,921			92,200,007		51
74,781	3,548,135	16,261,097	396,542,783		52
		-16,261,097	317,098,187		53
			1,210,859		54
			36,956,731		55
			1,916,220		56
			4,471,521		57
5,639,971	7,105,942	795,107	1,582,313,547		58
					59
9		2,828,064	40,668,097		60
			8,102,681		61
3,700,732		-795,330	471,366,229		62
			1,101,221		63
2,489,484	6,819,944		394,068,682		64
6,099,616			470,354,756		65
1,160,218		2,129	742,386,101		66
5,688,922		-2,129	982,990,157		67
3,768,689			499,516,821		68
184,608		251,597	189,025,800		69
8,296,562	5,886,026	-251,597	187,245,608		70
					71
					72
352,231			57,241,160		73
			2,342,551		74
31,741,071	12,705,970	2,032,734	4,046,409,864		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			5,116,918		86
	2,508,356		72,979,268		87
12,788,665		139,526	20,605,311		88
26,389		1,676,090	11,203,022		89
			170,597		90
3,189	1,053,700		14,283,962		91
189,229			7,819,786		92
		-1,676,090	4,825,233		93
862,643	1,745,124	-172,050	93,796,486		94
			277,392		95
13,870,115	5,307,180	-32,524	231,077,975		96
					97
					98
13,870,115	5,307,180	-32,524	231,077,975		99
75,989,852	37,527,847	2,918,269	10,104,284,234		100
					101
					102
					103
75,989,852	37,527,847	2,918,269	10,104,284,234		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	DISTRIBUTION E3600 - AUTUMN GLEN SUBSTATION LAND	3/30/2009	1/31/2021	770,620
3	DISTRIBUTION E3600 - BAINBRIDGE SUBSTATION LAND	2/28/2009	1/1/2029	618,393
4	DISTRIBUTION E3600 - BEL-RED SUBSTATION LAND	12/31/2009	1/31/2020	2,184,108
5	DISTRIBUTION E3600 - BETHEL SUBSTATION LAND	12/31/2005	1/31/2025	710,313
6	DISTRIBUTION E3600 - BUCKLEY SUBSTATION LAND	1/5/2009	12/31/2019	488,522
7	DISTRIBUTION E3600 - CARPENTER SUBSTATION LAND	4/28/2009	1/31/2029	1,041,420
8	DISTRIBUTION E3890 - CLYDE HILL SUBSTATION LAND	10/1/2014	1/31/2024	397,742
9	DISTRIBUTION E3600 - JENKINS CREEK SUBSTATION LAND	10/30/2009	1/31/2019	1,000,290
10	DISTRIBUTION E3600 - KENDALL SUBSTATION LAND	1/31/2010	1/31/2025	353,720
11	DISTRIBUTION E3600 - LAKE HOLMS SUBSTATION LAND	1/1/2012	1/31/2021	912,413
12	DISTRIBUTION E3600 - MITIGATION LAND GOPHER	12/31/2018	12/31/2019	2,081,903
13	DISTRIBUTION E3600 - PLUM STREET SUBSTATION LAND	2/28/2014	1/31/2025	305,609
14	TRANSMISSION E3500 - BPA KITSAP NAVAL TRANS PLANT	12/31/1992	10/1/2019	436,566
15	TRANSMISSION E3501 -BPA KITSAP NAVAL YARD TRANS	1/21/2016	12/31/2022	460,720
16	TRANSMISSION E3500 -HAZELWOOD SUBSTATION - LAND	1/31/2014	1/1/2022	460,994
17	TRANSMISSION E3500 -HOFFMAN SWITCHING STATION DISTR	3/31/2005	1/31/2021	714,663
18	TRANSMISSION E3557 / E3567 -SAINT CLAIR - PLEASANT	1/31/2014	1/31/2029	1,870,639
19	TRANSMISSION E3507 -SO. BREMERTON-BANGOR LAND	9/4/2007	12/31/2020	1,005,331
20	INTANGIBLE E303 - LOWER SNAKE RIVER WIND	3/31/2014	12/31/2020	22,243,546
21	Other Property:			
22	OTHER PROPERTY (less than $250,000)			515,135
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			38,572,647

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	3rd AC Intertie Project	2,741,018
2	ADMS-Distribution Management System	7,906,327
3	AMI Project	8,226,274
4	Bainbridge Island Substation Transmission Loop Project	2,014,672
5	Baker Project	34,562,475
6	Bellingham-Sedro #4 Project	18,192,581
7	Berrydale-Krain Transmission Line Project	1,375,711
8	Bremerton-Bangor Project	1,455,919
9	Buckley Substation Project	1,569,828
10	Eastside Transmission Project	69,530,354
11	EMS Upgrade	9,191,618
12	Fredonia Project	3,777,562
13	Greenwater Tap Project	1,295,640
14	Hansville Upgrade	2,391,377
15	Kent 228th St. Upgrade	2,311,173
16	Maxwelton Substation Project	5,837,685
17	Phantom Lake - Lake Hills Project	2,211,528
18	Sammamish-Juanita Transmission Project	7,454,337
19	Sedro March Point 230 Remediate Rebuild	1,579,352
20	Skookumchuck Wind Farm	2,656,352
21	Sound Transit East Link	2,158,214
22	Woodland - St Clair Project	3,264,428
23	WSDOT	1,401,987
24		
25	Electric Distribution - Misc CWIP less than $1,000,000 each	74,132,575
26	Electric Transmission - Misc CWIP less than $1,000,000 each	11,419,530
27	Electric General Plant & Intangibles - Misc CWIP less than $1,000,000 each	5,537,112
28	Electric Generation - Misc CWIP less than $1,000,000 each	8,099,864
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	292,295,493

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	3,764,636,606	3,764,474,181	162,425	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	316,437,876	316,437,876		
4	(403.1) Depreciation Expense for Asset Retirement Costs	19,240,378	19,240,378		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	335,678,254	335,678,254		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	65,076,472	65,076,472		
13	Cost of Removal	27,167,275	27,167,275		
14	Salvage (Credit)	217,205	217,205		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	92,026,542	92,026,542		
16	Other Debit or Cr. Items (Describe, details in footnote):	-11,348,827	-11,348,827		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,996,939,491	3,996,777,066	162,425	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	925,405,894	925,405,894		
21	Nuclear Production				
22	Hydraulic Production-Conventional	182,774,348	182,774,348		
23	Hydraulic Production-Pumped Storage				
24	Other Production	788,161,680	788,161,680		
25	Transmission	517,008,940	516,846,515	162,425	
26	Distribution	1,499,115,613	1,499,115,613		
27	Regional Transmission and Market Operation				
28	General	84,473,016	84,473,016		
29	TOTAL (Enter Total of lines 20 thru 28)	3,996,939,491	3,996,777,066	162,425	

Schedule Page: 219 Line No.: 16 Column: b

Included transfers, gain/loss and manual adjustment

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	PUGET WESTERN, INC.	05/31/1960		
2	Common			10,200
3	Retained Earnings			-19,215,429
4	Additional Paid in Capital			44,487,244
5	Subtotal			25,282,015
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ -541,432		TOTAL	25,282,015

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		10,200		2
-541,432		-19,756,861		3
		44,487,244		4
-541,432		24,740,583		5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
-541,432		24,740,583		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	17,266,161	19,826,388	
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	85,775,588	94,863,106	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	7,964,649	9,404,016	Electric & Gas
8	Transmission Plant (Estimated)	620,463	819,033	Electric & Gas
9	Distribution Plant (Estimated)	9,603,173	8,863,340	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	3,509,771	2,664,093	Electric & Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	107,473,644	116,613,588	Electric & Gas
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	150,639	277,440	Electric & Gas
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	-502,989	-456,332	Electric & Gas
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	124,387,455	136,261,084	

Schedule Page: 227   Line No.: 11   Column: b

These accounts are primarily from damage claims, miscellaneous projects for customers at the customer's premises, and various other merchandising materials.

Schedule Page: 227   Line No.: 14   Column: b

This account is for landfill gas pipeline imbalance.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	48,212.00	32,064	9,033.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Talen Montana	-3,596.00			
10	Puget Sound Energy				
11					
12					
13					
14					
15	Total	-3,596.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	19.00			
19	Other:				
20	Charges to Account 242	675.00	9,508		
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	43,922.00	22,556	9,033.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	5,381.00			
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA	261.00			
39	Cost of Sales				
40	Balance-End of Year	5,120.00			
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)		10		
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2020 No. (f)	2020 Amt. (g)	2021 No. (h)	2021 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
9,030.00		9,034.00		235,022.00		310,331.00	32,064	1
								2
								3
								4
								5
								6
								7
								8
						-3,596.00		9
				3,686.00		3,686.00		10
								11
								12
								13
								14
				3,686.00		90.00		15
								16
								17
						19.00		18
								19
						675.00	9,508	20
								21
								22
								23
								24
								25
								26
								27
								28
9,030.00		9,034.00		238,708.00		309,727.00	22,556	29
								30
								31
								32
								33
								34
								35
						5,381.00		36
								37
						261.00		38
								39
						5,120.00		40
								41
								42
							10	43
								44
								45
								46

Schedule Page: 228 Line No.: 9 Column: a

Previously, PPL Montana. Talen Montana is the operator and co-owner of the Colstrip Generating Facility.

Schedule Page: 228 Line No.: 36 Column: b

The following table reflects 2018 estimated beginning and end of year balances and associated sales of allowances held by the Environmental Protection Agency (EPA). Because the EPA does not provide a definite number of allowances sold upon remittance of sales proceeds, the figures below were estimated based on the weighted average cost from months when the sales were held.

Plant	12/31/17 Estimated Balance of Withheld Allowances Years 2009-2025	Estimated EPA Withheld Allowances Sold During 2018	12/31/18 Estimated Balance of Withheld Allowances Years 2009-2025
Colstrip Unit 1	1,376	107	1,269
Colstrip Unit 2	1,349	106	1,243
Colstrip Unit 3	762	27	735
Colstrip Unit 4	1,894	21	1,873
	5,381	261	5,120

Schedule Page: 228 Line No.: 43 Column: c

2018 proceeds from sales of allowances withheld by the Environmental Protection Agency were as follows:

Plant	2018 Proceeds
Colstrip Unit 1	4
Colstrip Unit 2	4
Colstrip Unit 3	1
Colstrip Unit 4	1
Total Proceeds	$ 10

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	2012 Storm	54,592,489		407	9,061,380	45,531,109
2	2014 Storm	17,667,580		407	16,261,536	1,406,044
3	2015 Storm	24,158,235				24,158,235
4	2016 Storm	10,437,020				10,437,020
5	2017 Storm Excess Costs	9,437,656	3,270,202			12,707,858
6	2017 Storm Recovery	12,215,519				12,215,519
7	2018 Storm Excess Costs		11,874,754			11,874,754
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL	128,508,499	15,144,956		25,322,916	118,330,539

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Electron Unrecovered Plant Costs	3,786,307		407	3,786,307	
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	3,786,307			3,786,307	

Schedule Page: 230 Line No.: 1 Column: a

The 2010 storm deferral cost was over-amortized beginning in 2016, and the over-amortized balance was approved by WUTC Dockets UE-170033 and UG-170034 to be applied to offset the remaining balances first on the 2006 storm deferral cost, and then any remaining credit be applied to the 2012 storm deferral cost. This caused a credit of ($5,386,340) to reduce the 2012 storm deferral cost. Additionally, the WUTC approved amortization of the remaining 2012 storm deferral cost over a period of 6 years, beginning in December 2017.

Schedule Page: 230 Line No.: 2 Column: a

The 2017 General Rate Case on Dockets UE-170033 and UG-170034 was approved by the WUTC to amortize 2010-2017 storm deferral costs over a 4 year period, beginning in December 2017. The storms were to be amortized at a total monthly rate of $1,355,128, with a prorated amortization of $518,093 occuring in December 2017. The storm deferrals are to be amortized in order of occurrence, beginning with the 2014 storm deferral cost.

Schedule Page: 230 Line No.: 21 Column: a

In November 2014, WUTC approved Docket UE-141141 granting PSE’s request for the recovery of Electron Unrecovered Plant cost as a regulatory asset amortized over 48 months. Monthly amortization for the regulatory costs commenced in December 2014 for $3,391,500 annually, and was then adjusted per the 2017 GRC resulting in amortization of $3,786,307 for 2018. The amortization was completed in November 2018.

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	NONE				
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Grays Harbor Feasibility Study	6,917	186051048		n/a
23	Grays Harbor System Impact Study	4,033	186051050		n/a
24	Schnebly Coulee Solar Facilities y	23,992	186051233		n/a
25	Loki Solar Park 105.4 MW LGIA	232	186052887		n/a
26	Maria Energy Storage Phase 1	778	186052891		n/a
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Unamortized Energy Conservation Costs	35,537,701	296,427,318	182.3, 908	301,264,270	30,700,749
2	WUTC Deferred AFUDC	50,300,536	4,229,182	406	2,500,925	52,028,793
3	Colstrip 1&2 Western Energy Coal Reserve - 10 years	4,718,288		406, 501	1,076,478	3,641,810
4	Colstrip 3&4 Deferred Depreciation - 17.5 years	900,037		406	138,804	761,233
5	BPA Power Exchange - 27.5 years		113,632,921	182.3	113,632,921	
6	Regulatory Tax Asset	797,363	4,915,161	182.3	5,712,524	
7	Environmental Remediation Costs	50,989,468	7,435,408	Multiple	18,399,479	40,025,397
8	Property Tax Tracker	36,517,226	71,909,817	408	62,805,201	45,621,842
9	Decoupling Mechanism	93,798,946	170,401,532	Multiple	197,586,112	66,614,366
10	Low Income Home Energy Assistance Program	(36,776)	24,158,317	Multiple	24,121,541	
11	Power Cost Adjustment Mechanism	4,576,280	187,822	557, 419	29,104	4,734,998
12	Power Cost Imbalance Recovery Deferral	4,969,864		557, 182.3	4,969,864	
13	White River Regulatory Asset - 3 years	19,501,592		182.3, 407	6,535,937	12,965,655
14	Chelan PUD - 20 years	98,051,574		555	7,088,065	90,963,509
15	Mint Farm Deferral - 15 years	20,750,387		407.3	2,885,052	17,865,335
16	Lower Snake River Deferral - 25 years	76,323,529		253, 407.3	4,230,168	72,093,361
17	Ferndale Deferral - 6 years	8,287,438		407.3	4,520,424	3,767,014
18	Baker Deferral - 5 years	561,113		407.3	561,113	
19	Snoqualmie Deferral - 5 years	2,203,422		407.3	2,203,422	
20	Credit Card Fee Deferral - 3 years	3,720,373	6,677	182.3, 407	1,439,398	2,287,652
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	512,468,361	693,304,155		761,700,802	444,071,714

Schedule Page: 232 Line No.: 1 Column: a

Included in Washington Commission Dockets UE-080389, UG-080390, UE-970686 and UG-120812.

Schedule Page: 232 Line No.: 2 Column: a

Included in Washington Commission Dockets UE-130137, UG-130138, UE-072300 and UG-072301.

Schedule Page: 232 Line No.: 3 Column: a

Included in Washington Commission Dockets UE-111048 and UG-111049. Amortization expires in December 2019.

Schedule Page: 232 Line No.: 4 Column: a

Included in Washington Commission Dockets UE-072300 and UG-072301. Amortization expires in May 2024.

Schedule Page: 232 Line No.: 5 Column: a

Included in Washington Commission Dockets UE-89-2688-T and UE-090704. Amortization expired in June 2017. Balance was written off in January 2018.

Schedule Page: 232 Line No.: 6 Column: a

No docket number required. FAS 109 balance.

Schedule Page: 232 Line No.: 7 Column: a

Included in Washington Commission Dockets UE-991796, UE-072300, UG-072301, UE-911476, UE-021537, UE-130137 and UG-130138.

Schedule Page: 232 Line No.: 8 Column: a

Included in Washington Commission Dockets UE-111048, UG-111049, and UE -140599 effective May 1, 2014.

Schedule Page: 232 Line No.: 9 Column: a

Included in Washington Commission Dockets UE-170033 and UG-170034.

Schedule Page: 232 Line No.: 11 Column: a

Included in Washington Commission Docket UE-011570. Total includes interest recorded on the customer balance of the PCA.

Schedule Page: 232 Line No.: 12 Column: a

Included in Washington Commission Dockets UE16112 and UE130617. Amortization expired in June 2017. Balance was written off in January 2018.

Schedule Page: 232 Line No.: 13 Column: a

Included in Washington Commission Dockets UE-170033 and UG-170034. New GRC 2017 for White River amortization of 3 years. Effective December 19, 2017 and expires in December 2020.

Schedule Page: 232 Line No.: 14 Column: a

Included in Washington Commission Dockets UE-060266 and UE-060539. Amortization began in November 2011 and expires in October 2031.

Schedule Page: 232 Line No.: 15 Column: a

Included in Washington Commission Docket UE-090704. Amortization began in April 2010 and expires in March 2025.

Schedule Page: 232 Line No.: 16 Column: a

Included in Washington Commission Dockets UE-111048, UG-111049, UE-130583, UE-131099 and UE-131230. Amortization began in May 2012 and expires in April 2037.

Schedule Page: 232 Line No.: 17 Column: a

Included in Washington Commission Dockets UE-141141, UE-130617, UE-131230, UE-131099 and UE-130583. Amortization is for 6 years which began in November 2013 and expires in October 2019.

Schedule Page: 232 Line No.: 18 Column: a

Included in Washington Commission Dockets UE-141141, UE-130617, UE-131230, UE-131099 and UE-130583. Amortization is for 5 years which began in November 2013 and expired in October 2018.

Schedule Page: 232 Line No.: 19 Column: a

Included in Washington Commission Dockets UE-141141, UE-130617, UE-131230, UE-131099 and UE-130583. Amortization is for 5 years which began in November 2013 and expired in October 2018.

Schedule Page: 232 Line No.: 20 Column: a

Included in Washington Commission Dockets UE-170033 and UG-170034. PSE sought recovery of the deferral in rates that become effective December 19, 2017 and expires in December 2020.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Incurred not Report Worker Comp	2,332,928	1,386,338	186,253	441,269	3,277,997
2	Carbon Offset Program	159,205	13,733	253	66,405	106,533
3	Damage Claim	3,432,362	20,406,394	186	20,385,223	3,453,533
4	Clearing Account Charges	545,675	264,445	184,186	1,057,610	-247,490
5	FAS133 Net Unrealized	26,030,490	182,783,255	244	194,074,306	14,739,439
6	Chelan Prepayments - 20 Yrs	6,612,932	139,675	555	488,141	6,264,466
7	Ferndale Maintenance - 12 Yrs	2,284,697		553	240,494	2,044,203
8	Encogen Maintenance - 10 Yrs	9,833,730	52,321	553	1,190,073	8,695,978
9	Environmental Remediation Exp	30,560,578	12,740,535	186,228	6,981,604	36,319,509
10	Real Estate Oper Leases - 7 Yrs	7,565,842	2,437,817	Various	229,331	9,774,328
11	FSAS 71 - Snoqualmie License	7,341,235	65,620	253		7,406,855
12	Baker Article	5,150,432	108,588	242	331,392	4,927,628
13	SFAS 71 - Baker License	54,817,487	969,989	253	180,157	55,607,319
14	Colstrip Maintenance - 3 Yrs	8,757,629	4,993,606	Various	6,902,500	6,848,735
15	Montana Comm Transition Fund	5,000,000		108	4,287,263	712,737
16	Fredonia Maintenance - 9 Yrs	4,486,648		553	699,028	3,787,620
17	Fredrickson Maintenance - 7 Yrs	5,873,230		513,553	1,124,444	4,748,786
18	Goldendale Maintenance 4-8 Yrs	2,230,596	867,440	514,553	705,485	2,392,551
19	Whitehorn Maintenance - 6 Yrs	1,752,816	937,094	186,553	404,496	2,285,414
20	Mint Farm Maintenance - 3-7 Yrs	3,269,292	233,187	513,553	1,479,329	2,023,150
21	Sumas Maintenance - 11 Yrs	3,490,182	16,417	553	311,155	3,195,444
22	Non-Temp Facility	3,711,786	11,473,558	186	8,663,874	6,521,470
23	Residential Exchange		2,807,590	253		2,807,590
24	Minor Items	231,535	39,325,649	186	39,396,240	160,944
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	195,471,307				187,854,739

Schedule Page: 233 Line No.: 8 Column: a

18605081 ENC Unit #3 Main 2017 JR490 - December 2018 ending balance versus amortization schedule discrepancy corrected in 2019.

Schedule Page: 233 Line No.: 17 Column: a

18603041 FRE U2 Hot Gas Inspection JR326 - December 2017 and 2018 ending balance versus amortization schedule discrepancy corrected in 2019.

Schedule Page: 233 Line No.: 18 Column: a

18603011 GLD Stm Tur Inspection 2014 JR329 - December 2017 ending balance versus amortization schedule discrepancy corrected in 2018.

Schedule Page: 233 Line No.: 20 Column: a

18604011 MTF ST FP Ins 2017 JR523 - December 2017 and 2018 ending balance versus amortization schedule discrepancy corrected in 2019.

Schedule Page: 233 Line No.: 21 Column: a

18604021 SUM CT Gen Major Inspection JR493 - December 2018 ending balance versus amortization schedule discrepancy corrected in 2019.

Schedule Page: 233 Line No.: 23 Column: a

2017/Q4 Line 23 was Shelf Registration. Accounts involved have no 2018 activity and were blocked. Line 23 was re-purposed to Residential Exchange which is a new 2018 line item.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	SFAS109	662,137,876	635,356,819
3	Production Tax Credit	187,617,117	121,616,101
4	Pension and Other Compensation	60,675,058	69,351,222
5	Regulatory Assets	54,407,305	41,983,848
6	Derivative Instruments	17,615,309	12,792,839
7	Other	25,194,350	38,808,916
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,007,647,015	919,909,745
9	Gas		
10	SFAS109	350,919,646	341,225,136
11	Derivative Instruments	7,779,306	6,399,076
12	Pension and Other Compensation	4,284,321	4,033,820
13	Regulatory Assets	2,245,299	2,647,274
14			
15	Other	2,629,057	1,945,963
16	TOTAL Gas (Enter Total of lines 10 thru 15	367,857,629	356,251,269
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,375,504,644	1,276,161,014

Notes

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201 - Common Stock	150,000,000	0.01	
2				
3	Total Common	150,000,000		
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
85,903,791	859,038					1
						2
85,903,791	859,038					3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 211 - Miscellaneous Paid in Capital	2,804,096,691
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	2,804,096,691

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Account 214 - Common Stock Expense	7,133,879
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	7,133,879

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221		
2			
3	First Mortgage Bonds Senior MTN 7.02% Series A	300,000,000	3,010,746
4	First Mortgage Bonds Senior MTN 6.74% Series A	200,000,000	2,018,425
5	First Mortgage Bonds Senior MTN 7.00% Series B	100,000,000	954,608
6	5.483% Senior Notes Due 06/35	250,000,000	2,460,125
7	6.724% Senior Notes Due 06/36	250,000,000	2,527,628
8	6.274% Senior Notes Due 03/37	300,000,000	2,921,148
9	Junior Subordinated Notes (Hybrid) 6.974%	250,000,000	4,400,860
10	5.757% Senior Notes Due 10/39	350,000,000	3,557,361
11	5.795% Senior Notes Due 03/40	325,000,000	3,384,066
12	5.764% Senior Notes Due 07/40	250,000,000	2,587,276
13	4.434% Senior Notes Due 11/41	250,000,000	2,592,616
14	4.700% Senior Notes Due 11/51	45,000,000	511,229
15	5.638% Senior Notes Due 04/41	300,000,000	3,071,895
16	5.638% Senior Notes Due 04/41 (D)		15,000
17	4.300% Senior Notes Due 05/45	425,000,000	3,718,750
18	4.300% Senior Notes Due 05/45 (D)		1,912,500
19	4,223% Senior Notes Due 06/48	600,000,000	1,429,461
20	3.9% Pollution Control Bonds Rev Series 2013A	138,460,000	1,473,301
21	4.0% Pollution Control Bonds Rev Series 2013B	23,400,000	248,243
22	SUBTOTAL	4,356,860,000	42,795,238
23			
24	Bonds assumed which were originally issued by Washington Natural Gas Company		
25			
26	Secured Medium Term Notes - 7.15% Series C	15,000,000	112,500
27	Secured Medium Term Notes - 7.20% Series C	2,000,000	15,000
28	SUBTOTAL	17,000,000	127,500
29			
30			
31			
32			
33	TOTAL	4,373,860,000	42,922,738

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
12/22/97	12/01/27	12/22/97	12/01/27	300,000,000		3
06/15/98	06/15/18	06/15/98	06/15/18			4
03/09/99	03/09/29	03/09/99	03/09/29	100,000,000		5
05/27/05	06/01/35	05/27/05	06/01/35	250,000,000		6
06/30/06	06/15/36	6/30/06	06/15/36	250,000,000		7
09/18/06	03/15/37	9/18/06	03/15/37	300,000,000		8
06/01/07	06/01/67	06/01/07	06/01/67			9
09/11/09	10/01/39	09/11/09	10/01/39	350,000,000		10
03/08/10	03/15/40	03/08/10	03/15/40	325,000,000		11
06/29/10	07/15/40	06/29/10	07/15/40	250,000,000		12
11/16/11	11/15/41	11/16/11	11/15/41	250,000,000		13
11/22/11	11/15/51	11/22/11	11/15/51	45,000,000		14
03/25/11	04/15/41	3/25/11	04/15/41	300,000,000		15
						16
05/26/15	05/20/45	5/26/15	05/20/45	425,000,000		17
						18
06/04/18	06/15/48	06/04/18	06/15/48	600,000,000		19
05/23/13	03/01/31	5/23/13	03/01/31	138,460,000		20
05/23/13	03/01/31	5/23/13	03/01/31	23,400,000		21
				3,906,860,000		22
						23
						24
						25
12/20/95	12/19/25	12/20/95	12/19/25	15,000,000		26
12/22/95	12/22/25	12/22/95	12/22/25	2,000,000		27
				17,000,000		28
						29
						30
						31
						32
				3,923,860,000		33

Schedule Page: 256 Line No.: 28 Column: a

The total of Account 427 includes an additional $487,644 of treasury lock and forward swap interest expenses not reported in the Interest for Year Amount (i).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	317,163,809
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Provision for federal Income Taxes	50,843,595
11	Others	183,882,627
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Others	133,153,097
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	
28	Show Computation of Tax:	
29	Book Net Income	317,163,809
30	Federal Income Tax	50,843,595
31		
32	Increase Taxable Income	183,882,627
33	Decrease Taxable Income	-133,153,097
34	Federal Taxable Income	418,736,934
35	Fed Benefit of State Tax	-417,966
36	Net Federal Taxable Income	418,318,968
37	Federal Tax Expense Before Credits	87,846,983
38	Less: Production Tax Credit & AMT	68,563,584
39	Current Federal Tax Payable	19,283,399
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 11 Column: b

Line 11 Details:	
Capitalized Interest	13,153,366
Conservation Activity	4,836,952
Decoupling Revenue	15,989,039
Depreciation Related Activity	39,303,940
Electric and Gas Purchase Contracts	1,229,348
Environmental Costs	8,567,846
Non-Deductible Items	33,358,751
Renewable Energy Credits	844,765
Regulatory Assets	56,420,659
Storm Related Activity	10,177,960
Subtotal	183,882,627
Line 20 Details:	
Allowance for Funds Used During Cons	(33,025,103)
Derivative Instruments	(41,661,501)
Property Tax Rate Tracker	(12,495,440)
Pensions and Other Compensation	(14,980,969)
Other Adjustment	(7,841,809)
Treasury Grant Amortization	(23,148,274)
Subtotal	(133,153,097)

Line 29 Details:	2018
Book Net Income	317,163,809
Addback Total Income Tax	50,843,595
PTBI	368,007,404
Increase Taxable Income	183,882,627
Decrease Taxable Income	(133,153,097)
Federal Taxable Income	418,736,934
Fed Benefit of State Tax	(417,966)
Net Federal Taxable Income	418,318,968
2018 Federal Tax Rate	21%
Federal Tax Expense Before Credits	87,846,983
Less: Production Tax Credit&AMT	68,563,584
FIT Payable	19,283,399
Deferred Tax Expense	31,122,614
Total Federal Tax Provision	50,406,013

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	FEDERAL					
2	Income	-1,930,464		19,283,399	-17,857,032	
3	Employment	12,970		25,107,331	-24,627,625	
4	Other		1,860	3,720	-1,860	
5						
6	STATE					
7	Property	74,434,930		90,430,644	-83,644,491	
8	State Excise	21,471,710		118,810,942	-122,012,670	
9	Municipal Excise	17,931,843		122,090,485	-123,684,632	
10	Other State Taxes	2,920,158		5,458,716	-7,354,487	
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	114,841,147	1,860	381,185,237	-379,182,797	

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-504,098		54,348,132		-27,333,180	-34,909,998	2
492,677		9,000,846			16,106,485	3
					3,720	4
						5
						6
81,221,084		59,265,945			31,164,699	7
18,269,985		82,738,819			36,072,123	8
16,337,694		82,000,442			40,090,042	9
1,024,385		1,346,485			4,112,232	10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
116,841,727		288,700,669		-27,333,180	92,639,303	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7							
8	TOTAL						
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Deferred Comp - Salary	7,366,980	Various	5,072,819	5,952,491	8,246,652
2	SFAS 106 Unfunded Liability	23,974,617	417	17,288,105	22,975,843	29,662,355
3	Low Income Program	13,525,474	Various	32,904,134	37,393,413	18,014,753
4	Sch 85 Line Extension Cost	11,372,553	456	402,047	1,466,935	12,437,441
5	Green Power Tariff	5,812,374	456	2,553,368	2,800,940	6,059,946
6	Landlord Incentives - 5-11 Yrs	5,242,961	931	2,117,779	96,546	3,221,728
7	PTC Deferred Post June '10	143,874,194	407	98,863,832	15,318,247	60,328,609
8	Workers Comp - IBNR	2,332,927	186	50,631	1,012,758	3,295,054
9	Residential Exchange	-663,658	555	127,675,968	128,339,625	-1
10	Operating Leases Obligation	7,378,561	186	126,401	2,426,919	9,679,079
11	Decoupling	-1		1,665,331	2,500,689	835,357
12	LSR License O&M - 25 Yrs	9,885,787	Various	8,737,283	8,305,679	9,454,183
13	Snoqualmie License O&M	8,066,931	419	725,697	65,621	7,406,855
14	Ferndale License Misc Def - 6 Yrs	992,389	419	541,303		451,086
15	Baker License Misc Def	54,999,959	Various	362,628	969,989	55,607,320
16	Unearned Revenue - 11-20 Yrs	3,706,583	454	7,286,736	4,402,404	822,251
17	Deferred Pole Contact	497,863		6,604,273	6,106,411	1
18	PGA Unrealized Gain			34,808,312	34,808,312	
19	Int'l Paper Wcst Cap	8,921,989	804	8,921,988		1
20	Montana PTC	2,122,853	Various	117,604,389	197,292,811	81,811,275
21	Unclaimed Property	9,281	131	653,953	592,461	-52,211
22	Colstrip 3&4 Final	36,672	131	702,592	723,910	57,990
23	Mint Farm Misc Def Credit - 15 Yrs	6,431,437	419	884,724		5,546,713
24	Deferred Interchange		555	8,021,626	8,021,626	
25	Tacoma LNG		107	8,395,000	8,895,000	500,000
26	Minor Items	121,622	Various	194,350	270,661	197,933
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	316,010,348		493,165,269	490,739,291	313,584,370

Schedule Page: 269   Line No.: 25   Column: a

New 2018 Line Item added for Tacoma LNG. Line 25 was previously Minor Items which was moved to Line 26. 2018 ending balance should be $500,000. SAP does not reflect a $1M topside debit entry done in December 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,431,442,955	5,962,806	39,231,977
3	Gas	602,885,391	5,952,090	8,290,364
4				
5	TOTAL (Enter Total of lines 2 thru 4)	2,034,328,346	11,914,896	47,522,341
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	2,034,328,346	11,914,896	47,522,341
10	Classification of TOTAL			
11	Federal Income Tax	2,034,328,346	11,914,896	47,522,341
12	State Income Tax			
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
						1,398,173,784	2
						600,547,117	3
							4
						1,998,720,901	5
							6
							7
							8
						1,998,720,901	9
							10
						1,998,720,901	11
							12
							13

NOTES (Continued)

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	SFAS109	797,365		
4	Pension related	42,087,535	1,989,647	743,523
5	Storm Damage	44,977,975	3,183,170	5,320,542
6	Derivative Instruments	7,413,847	30,757,993	26,579,898
7	Regulatory Assets	60,524,028	13,032,869	15,032,952
8	Other	10,998,413	3,177,470	1,447,258
9	TOTAL Electric (Total of lines 3 thru 8)	166,799,163	52,141,149	49,124,173
10	Gas			
11	Pension related	3,720,117	1,044,276	390,242
12	Derivative Instruments	7,779,306	16,931,403	18,311,633
13	Regulatory Assets	33,625,033	2,579,753	10,845,730
14	Other	764,166	341,215	115,581
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	45,888,622	20,896,647	29,663,186
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	212,687,785	73,037,796	78,787,359
20	Classification of TOTAL			
21	Federal Income Tax			
22	State Income Tax			
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		Various	797,365				3
						43,333,659	4
						42,840,603	5
		Various	149,244			11,442,698	6
25,581		Various	-87,826			58,637,352	7
		Various	87,825	Various		12,640,800	8
25,581			946,608			168,895,112	9
							10
						4,374,151	11
						6,399,076	12
13,067						25,372,123	13
						989,800	14
							15
							16
13,067						37,135,150	17
							18
38,648			946,608			206,030,262	19
							20
							21
							22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Unamort. Gain from Disposition of Allowance	5,604	411.8	4,408		1,196
2	Summit Purchase Buyout	4,462,500	456, 495	1,575,000		2,887,500
3	BNP-Westcoast Cap Agrmnt-Non-Core-Gas	448,022	547	448,022		
4	FBE-Westcoast Cap Agrmnt-Non-Core-Gas	326,808	547	326,808		
5	Renewable Energy Credits	1,251,829	Multiple	1,787,866	1,945,210	1,409,173
6	Treasury Grants - Wind Project Expansion	379,138	407.4	15,862,770	15,943,773	460,141
7	PTC Cost Deferral	93,615,823	407.3, 403			93,615,823
8	Treasury Grants - Hydro Deferrals	1,781,885	407.4	1,781,885		
9	Decoupling Mechanisms	26,296,340	Multiple	75,734,374	63,195,958	13,757,924
10	Regulatory Liability Tax Reform	1,013,057,521	Multiple	1,186,143,088	1,149,667,519	976,581,952
11	Deferred Tax Rate Change		407.3	10,000,000	10,000,000	
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	1,141,625,470		1,293,664,221	1,240,752,460	1,088,713,709

Schedule Page: 278 Line No.: 1 Column: a

Included in Washington Commission Docket UE-001157. Effective in October 2000, each sale amortizes over ten years from the date of sale. Amortization expires in May 2018, May 2019, April 2020 and April 2021.

Schedule Page: 278 Line No.: 2 Column: a

Included in Washington Commission Docket UE-071876. Amortization expires in October 2020.

Schedule Page: 278 Line No.: 3 Column: a

Included in Washington Commission Docket UE-100503. Amortization expired October in 2018.

Schedule Page: 278 Line No.: 4 Column: a

Included in Washington Commission Docket UE-082013. Amortization expired October in 2018.

Schedule Page: 278 Line No.: 5 Column: a

Included in Washington Commission Dockets UE-111048 and UE-111049 (Schedule 137) effective January 1, 2018. The REC liablility balance is used to offset PTC receivables.

Schedule Page: 278 Line No.: 6 Column: a

Included in Washington Commission Docket UE-120277 "Interest on the unamortized balance of U.S. Treasury Department Grant" and UE-171086 (Schedule 95A) effective January 1, 2018. The updated name is to reflect the liabilities being reviewed which remains the same from previous quarters.

Schedule Page: 278 Line No.: 7 Column: a

Included in Washington Commission Dockets UE-070725, UE-101581, UE-170033, and UG-170034. The REC liability balance is used to offset PTC receivables.

Schedule Page: 278 Line No.: 8 Column: a

Included in Washington Commission Dockets UE-130583, UE-130617, UE-131099 and UE-131230. Included in Washington Commission Docket UE-141141. Amortization for Baker and Snoqalmie hyrdo deferrals expired in October 2018. Included in Washington Commission Docket UE-170033 and UG-170034 effective December 2017. The updated name is to reflect the liabilities being reviewed which remains the same from previous quarters.

Schedule Page: 278 Line No.: 9 Column: a

Included in Washington Commission Dockets UE-170033 and UG-170034 effective December 19, 2017.

Schedule Page: 278 Line No.: 10 Column: a

PSE re-evaluated it's deferred tax liability in December 2017 due to the 2017 Tax reform and has requested deferral accounting in a petition filed with the WUTC on December 29, 2017.

Schedule Page: 278 Line No.: 11 Column: a

PSE re-evaluated it's deferred tax liability in December 2017 due to the 2017 Tax reform and has requested deferral accounting in a petition filed with the WUTC on December 29, 2017. Balance was written off January 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,147,259,983	1,232,074,695
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	885,537,077	892,584,597
5	Large (or Ind.) (See Instr. 4)	114,058,620	116,098,287
6	(444) Public Street and Highway Lighting	18,378,087	19,375,607
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,165,233,767	2,260,133,186
11	(447) Sales for Resale	155,673,554	129,393,849
12	TOTAL Sales of Electricity	2,320,907,321	2,389,527,035
13	(Less) (449.1) Provision for Rate Refunds	24,054,569	
14	TOTAL Revenues Net of Prov. for Refunds	2,296,852,752	2,389,527,035
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,451,377	2,835,884
17	(451) Miscellaneous Service Revenues	12,237,816	11,948,891
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	18,352,788	18,039,330
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	84,129,102	-12,069,402
22	(456.1) Revenues from Transmission of Electricity of Others	29,059,353	27,330,952
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	146,230,436	48,085,655
27	TOTAL Electric Operating Revenues	2,443,083,188	2,437,612,690

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
10,497,389	10,931,999	1,010,574	998,078	2
				3
8,932,681	9,089,842	128,845	126,830	4
1,189,828	1,214,818	3,378	3,414	5
77,297	79,738	6,984	6,714	6
				7
				8
				9
20,697,195	21,316,397	1,149,781	1,135,036	10
5,384,631	5,910,970	8	8	11
26,081,826	27,227,367	1,149,789	1,135,044	12
				13
26,081,826	27,227,367	1,149,789	1,135,044	14

Line 12, column (b) includes $ 11,699 of unbilled revenues.

Line 12, column (d) includes 35,043 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 4 Column: b

This includes $79,908 of transportation revenue

Schedule Page: 300 Line No.: 4 Column: c

This includes $225,069 of transportation revenue

Schedule Page: 300 Line No.: 5 Column: b

This includes $3,451,986 of transportation revenue.

Schedule Page: 300 Line No.: 5 Column: c

This includes $3,281,569 of transportation revenue.

Schedule Page: 300 Line No.: 17 Column: b

Amounts Greater than $250,000 - (451) - Misc. Services Revenues

Conversion Sch 73 Revenue	$	0
Non-Consumption Utility Tax		305,958
Line Extension Revenue		1,064,858
Temporary Service Charge		1,314,248
Treble Damages		580,062
Reconnection Charge		1,460,925
Non-Consumption & Consumption Misc. Service Charges		2,407,581
Schedule 87 Tax Surcharge		4,541,829

Schedule Page: 300 Line No.: 17 Column: c

Amounts Greater than $250,000 - (451) - Misc. Services Revenues

Conversion Sch 73 Revenue	$	265,127
Non-Consumption Utility Tax		330,343
Line Extension Revenue		789,696
Temporary Service Charge		1,203,088
Treble Damages		1,257,168
Reconnection Charge		1,572,312
Non-Consumption & Consumption Misc. Service Charges		2,105,009
Schedule 87 Tax Surcharge		4,198,963

Schedule Page: 300 Line No.: 21 Column: b

Amounts Greater than $250,000 - (456) Other Revenues

Decoupling Revenues	1,850,774
Misc. O&M Revenue	262,047
Summit Buyout	1,026,108
Electric Over-Earnings	10,925,933
Gain/(Loss) on sales or assignment of Non-core Gas	69.470,812

Schedule Page: 300 Line No.: 21 Column: c

Amounts Greater than $250,000 - (456) Other Revenues

Decoupling Revenues	(23,598,934)
Lifetime O&M Revenue	369,759
Summit Buyout	1,026,108
Electric Over-Earnings	1,112,107
Gain/(Loss) on sales or assignment of Non-core Gas	8,809,643

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	0	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	0	0	0	0	0.0000
43	TOTAL	0	0	0	0	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Port of Bremerton	RQ	Sch005	0.133	0.133	0.133
2	Port of Brownsville	RQ	Sch005	0.131	0.131	0.131
3	City of Des Moines	RQ	Sch005	0.239	0.239	0.239
4	Kingston Port District	RQ	Sch005	0.104	0.104	0.104
5	Kittitas Co PUD	RQ	Sch005	0.022	0.022	0.022
6	City of Oak Harbor	RQ	Sch005	0.123	0.123	0.123
7	Poulsbo Port District	RQ	Sch005	0.086	0.086	0.086
8	Port of Skagit - LaConner Marina	RQ	Sch005	0.081	0.081	0.081
9	Port of Skagit - North Basin	RQ	Sch005	0.143	0.143	0.143
10	Change in Unbilled Revenue	RQ	Sch005			
11	Avangrid Renewables, LLC	AD	FERC #8			
12	Avangrid Renewables, LLC	OS	FERC #8			
13	Avangrid Renewables, LLC	OS	FERC #9			
14	Avista Corp. WWP Division	OS	FERC #8			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Avista Corp. WWP Division	OS	FERC #9			
2	BC Hydro	OS	FERC #9			
3	Black Hills Power, Inc.	OS	FERC #8			
4	Bonneville Power Administration	AD	FERC #8			
5	Bonneville Power Administration	AD	FERC #9			
6	Bonneville Power Administration	OS	FERC #8			
7	Bonneville Power Administration	OS	FERC #9			
8	BP Energy Company	OS	FERC #8			
9	Brookfield Energy Marketing LP	OS	FERC #8			
10	California ISO	OS	FERC #8			
11	Calpine Energy Services	OS	FERC #8			
12	Chelan County PUD	OS	FERC #8			
13	Chelan County PUD	OS	FERC #9			
14	Citigroup Energy Inc.	AD	FERC #8			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Citigroup Energy Inc.	OS	FERC #8			
2	Clatskanie Peoples Utility District	AD	FERC #8			
3	Clatskanie Peoples Utility District	OS	FERC #8			
4	ConocoPhillips Company	OS	FERC #8			
5	EDF Trading N.A., LLC	AD	FERC #8			
6	EDF Trading N.A., LLC	OS	FERC #8			
7	Energy Keepers, Inc.	OS	FERC #8			
8	Eugene Water & Electric Board	OS	FERC #8			
9	Exelon Generation Company LLC	OS	FERC #8			
10	Grant County PUD No.2	OS	FERC #8			
11	Grant County PUD No.2	OS	FERC #9			
12	Gridforce Energy Management, LLC.	OS	FERC #8			
13	Gridforce Energy Management, LLC.	OS	FERC #9			
14	Idaho Power Company	OS	FERC #8			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Idaho Power Company	OS	FERC #9			
2	Morgan Stanley Capital Group Inc.	OS	FERC #8			
3	NaturEner Power Watch, LLC	OS	FERC #9			
4	Nevada Power Company	OS	FERC #9			
5	NextEra Energy Marketing, LLC	OS	FERC #8			
6	NorthWestern Energy	OS	FERC #8			
7	NorthWestern Energy	OS	FERC #9			
8	P.U.D. No. 1 of Douglas County	OS	FERC #8			
9	P.U.D. No. 1 of Douglas County	OS	FERC #9			
10	P.U.D. No. 1 of Okanogan County	OS	FERC #8			
11	PacifiCorp	AD	FERC #8			
12	PacifiCorp	OS	FERC #8			
13	PacifiCorp	OS	FERC #9			
14	Portland General Electric Company	AD	FERC #8			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Portland General Electric Company	OS	FERC #8			
2	Portland General Electric Company	OS	FERC #9			
3	Powerex Corp.	OS	FERC #8			
4	Public Service Company of Colorado	OS	FERC #8			
5	Rainbow Energy Marketing	OS	FERC #8			
6	Sacramento Municipal Utility District	OS	FERC #9			
7	Seattle City Light Marketing	OS	FERC #8			
8	Seattle City Light Marketing	OS	FERC #9			
9	Shell Energy North America (US)	AD	FERC #8			
10	Shell Energy North America (US)	OS	FERC #8			
11	Snohomish County PUD	OS	FERC #8			
12	Tacoma Power	OS	FERC #8			
13	Tacoma Power	OS	FERC #9			
14	Talen Energy Marketing, LLC	OS	FERC #8			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	The Energy Authority	OS	FERC #8			
2	TransAlta Energy Marketing U.S.	AD	FERC #8			
3	TransAlta Energy Marketing U.S.	OS	FERC #8			
4	TransCanada Energy Sales Ltd.	OS	FERC #8			
5	Turlock Irrigation District	OS	FERC #9			
6	Vitol Inc.	AD	FERC #8			
7	Vitol Inc.	OS	FERC #8			
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
765	8,366	26,872	2,667	37,905	1
1,527	14,918	53,659	2,895	71,472	2
1,430	15,082	50,254	2,752	68,088	3
593	6,538	20,845	1,113	28,496	4
158	2,659	5,558		8,217	5
731	7,732	25,693	2,465	35,890	6
527	5,395	18,510	1,432	25,337	7
473	5,103	16,625	887	22,615	8
927	9,029	32,564	2,467	44,060	9
-47	-7	-1,642		-1,649	10
175			5,954	5,954	11
361,418		9,243,577		9,243,577	12
26		1,210		1,210	13
87,090		2,802,240		2,802,240	14
7,084	74,815	248,938	16,678	340,431	
5,377,547	0	155,302,766	30,357	155,333,123	
5,384,631	**74,815**	**155,551,704**	**47,035**	**155,673,554**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
13		439		439	1
51		937		937	2
150		3,675		3,675	3
			-119	-119	4
			-1	-1	5
297,061		9,955,939		9,955,939	6
148		2,463		2,463	7
56,286		1,968,712		1,968,712	8
380		23,800		23,800	9
656,076		18,333,021		18,333,021	10
229,823		3,815,628		3,815,628	11
54,800		1,957,780		1,957,780	12
14		639		639	13
			4	4	14
7,084	74,815	248,938	16,678	340,431	
5,377,547	0	155,302,766	30,357	155,333,123	
5,384,631	**74,815**	**155,551,704**	**47,035**	**155,673,554**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
466,796		13,582,557		13,582,557	1
			-10	-10	2
29,529		1,000,934		1,000,934	3
81,491		3,187,596		3,187,596	4
-26			-520	-520	5
21,836		352,637		352,637	6
1,703		90,348		90,348	7
61,885		1,619,790		1,619,790	8
108,890		4,771,166		4,771,166	9
-1		-49		-49	10
53		800		800	11
-2		-87		-87	12
681		27,230		27,230	13
103,096		3,523,268		3,523,268	14
7,084	74,815	248,938	16,678	340,431	
5,377,547	0	155,302,766	30,357	155,333,123	
5,384,631	**74,815**	**155,551,704**	**47,035**	**155,673,554**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
20		498		498	1
636,458		18,877,175		18,877,175	2
153		2,790		2,790	3
9		127		127	4
30		900		900	5
34,930		1,531,705		1,531,705	6
103		3,351		3,351	7
2,300		102,180		102,180	8
1					9
1,255		56,500		56,500	10
			53	53	11
129,637		4,042,724		4,042,724	12
352		11,889		11,889	13
			-160	-160	14
7,084	74,815	248,938	16,678	340,431	
5,377,547	0	155,302,766	30,357	155,333,123	
5,384,631	**74,815**	**155,551,704**	**47,035**	**155,673,554**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
100,025		2,836,938		2,836,938	1
103		4,645		4,645	2
549,446		13,255,195		13,255,195	3
40		226		226	4
6,591		237,930		237,930	5
39		1,881		1,881	6
76,840		2,180,488		2,180,488	7
8		278		278	8
			17,509	17,509	9
379,560		12,370,412		12,370,412	10
20,500		437,930		437,930	11
26,805		780,535		780,535	12
3		128		128	13
9		90		90	14
7,084	74,815	248,938	16,678	340,431	
5,377,547	0	155,302,766	30,357	155,333,123	
5,384,631	**74,815**	**155,551,704**	**47,035**	**155,673,554**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
213,670		7,534,623		7,534,623	1
26			7,645	7,645	2
441,279		12,183,584		12,183,584	3
123,042		2,245,852		2,245,852	4
5		146		146	5
			2	2	6
14,866		335,796		335,796	7
					8
					9
					10
					11
					12
					13
					14
7,084	74,815	248,938	16,678	340,431	
5,377,547	0	155,302,766	30,357	155,333,123	
5,384,631	**74,815**	**155,551,704**	**47,035**	**155,673,554**	

Schedule Page: 310 Line No.: 1 Column: j

Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 2 Column: j

Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 3 Column: j

Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 4 Column: j

Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 6 Column: j

Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 7 Column: j

Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 8 Column: j

Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 9 Column: j

Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 11 Column: j

Prior period adjustment and current period accounting adjustments.

Schedule Page: 310.1 Line No.: 4 Column: j

Prior period adjustment.

Schedule Page: 310.1 Line No.: 5 Column: j

Current period accounting adjustments.

Schedule Page: 310.1 Line No.: 14 Column: j

Current period accounting adjustments.

Schedule Page: 310.2 Line No.: 2 Column: j

Prior period adjustment.

Schedule Page: 310.2 Line No.: 5 Column: j

Prior period adjustment.

Schedule Page: 310.3 Line No.: 11 Column: j

Prior period adjustment.

Schedule Page: 310.3 Line No.: 14 Column: j

Prior period adjustment.

Schedule Page: 310.4 Line No.: 9 Column: j

Prior period adjustment.

Schedule Page: 310.5 Line No.: 2 Column: j

Prior period adjustment and current period accounting adjustments.

Schedule Page: 310.5 Line No.: 6 Column: j

Current period accounting adjustments.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,705,460	1,877,708
5	(501) Fuel	79,334,192	82,114,041
6	(502) Steam Expenses	9,075,849	9,146,030
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,790,939	1,772,475
10	(506) Miscellaneous Steam Power Expenses	11,281,399	8,402,000
11	(507) Rents	71,114	91,567
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	103,258,953	103,403,821
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,708,415	1,584,217
16	(511) Maintenance of Structures	1,786,439	2,326,399
17	(512) Maintenance of Boiler Plant	13,792,263	14,537,103
18	(513) Maintenance of Electric Plant	9,151,401	8,312,475
19	(514) Maintenance of Miscellaneous Steam Plant	3,636,763	2,632,690
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	30,075,281	29,392,884
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	133,334,234	132,796,705
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,191,353	1,939,540
45	(536) Water for Power		
46	(537) Hydraulic Expenses	3,603,020	3,574,389
47	(538) Electric Expenses	234,879	225,328
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,591,277	2,811,058
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	8,620,529	8,550,315
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	328,603	-26,068
54	(542) Maintenance of Structures	328,234	518,604
55	(543) Maintenance of Reservoirs, Dams, and Waterways	520,395	613,746
56	(544) Maintenance of Electric Plant	1,300,141	1,092,338
57	(545) Maintenance of Miscellaneous Hydraulic Plant	4,053,077	4,496,142
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,530,450	6,694,762
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	15,150,979	15,245,077

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	3,158,357	3,582,940
63	(547) Fuel	124,839,938	124,161,366
64	(548) Generation Expenses	10,960,994	10,204,130
65	(549) Miscellaneous Other Power Generation Expenses	5,198,887	5,282,197
66	(550) Rents	6,931,080	6,046,928
67	TOTAL Operation (Enter Total of lines 62 thru 66)	151,089,256	149,277,561
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	656,043	833,666
70	(552) Maintenance of Structures	754,814	683,121
71	(553) Maintenance of Generating and Electric Plant	29,404,802	30,994,118
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	842,726	1,447,593
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	31,658,385	33,958,498
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	182,747,641	183,236,059
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	496,710,087	457,449,402
77	(556) System Control and Load Dispatching	109,272	55,210
78	(557) Other Expenses	17,679,051	7,487,318
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	514,498,410	464,991,930
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	845,731,264	796,269,771
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,519,400	1,311,569
84			
85	(561.1) Load Dispatch-Reliability	152,208	66,490
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,612,805	514,540
87	(561.3) Load Dispatch-Transmission Service and Scheduling	548,215	261,540
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	2,417,054	2,377,867
90	(561.6) Transmission Service Studies		-58,375
91	(561.7) Generation Interconnection Studies	2,280,012	3,166,952
92	(561.8) Reliability, Planning and Standards Development Services	102,621	189,145
93	(562) Station Expenses	1,374,172	1,117,147
94	(563) Overhead Lines Expenses	340,841	552,712
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	115,807,778	117,598,896
97	(566) Miscellaneous Transmission Expenses	2,740,905	1,807,675
98	(567) Rents	372,875	109,301
99	TOTAL Operation (Enter Total of lines 83 thru 98)	130,268,886	129,015,459
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	80,644	83,714
102	(569) Maintenance of Structures	1,877	350
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	125,706	124,702
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,008,944	2,251,718
108	(571) Maintenance of Overhead Lines	6,637,104	6,795,628
109	(572) Maintenance of Underground Lines		11,180
110	(573) Maintenance of Miscellaneous Transmission Plant	124,119	209,961
111	TOTAL Maintenance (Total of lines 101 thru 110)	9,978,394	9,477,253
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	140,247,280	138,492,712

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,675,136	-11,707,899
135	(581) Load Dispatching	1,710,998	2,556,051
136	(582) Station Expenses	1,777,553	1,139,097
137	(583) Overhead Line Expenses	2,571,367	2,175,101
138	(584) Underground Line Expenses	4,555,493	4,910,092
139	(585) Street Lighting and Signal System Expenses	142,212	394,448
140	(586) Meter Expenses	1,704,988	-1,476,692
141	(587) Customer Installations Expenses	3,314,701	3,082,940
142	(588) Miscellaneous Expenses	12,068,387	17,982,536
143	(589) Rents	1,317,139	1,271,418
144	TOTAL Operation (Enter Total of lines 134 thru 143)	31,837,974	20,327,092
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	541,270	472,605
147	(591) Maintenance of Structures	-5	
148	(592) Maintenance of Station Equipment	1,486,799	1,840,993
149	(593) Maintenance of Overhead Lines	34,730,225	37,943,900
150	(594) Maintenance of Underground Lines	12,006,811	12,822,043
151	(595) Maintenance of Line Transformers	171,037	145,905
152	(596) Maintenance of Street Lighting and Signal Systems	1,958,092	2,255,930
153	(597) Maintenance of Meters	519,037	473,523
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of lines 146 thru 154)	51,413,266	55,954,899
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	83,251,240	76,281,991
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	130,944	128,434
160	(902) Meter Reading Expenses	11,224,995	10,825,732
161	(903) Customer Records and Collection Expenses	23,118,231	22,295,337
162	(904) Uncollectible Accounts	18,742,716	16,024,854
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	53,216,886	49,274,357

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	115,366,839	123,757,931
169	(909) Informational and Instructional Expenses	3,056,500	2,292,355
170	(910) Miscellaneous Customer Service and Informational Expenses	893	1,092
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	118,424,232	126,051,378
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	805,415	774,779
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		-5,467
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	805,415	769,312
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	48,105,340	53,959,621
182	(921) Office Supplies and Expenses	8,547,055	1,837,601
183	(Less) (922) Administrative Expenses Transferred-Credit	21,363,036	19,922,769
184	(923) Outside Services Employed	10,996,650	18,567,958
185	(924) Property Insurance	4,710,219	4,859,606
186	(925) Injuries and Damages	4,956,899	6,055,699
187	(926) Employee Pensions and Benefits	31,216,294	27,148,351
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	7,358,825	8,676,082
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		499
192	(930.2) Miscellaneous General Expenses	5,413,039	2,369,220
193	(931) Rents	6,812,985	8,493,021
194	TOTAL Operation (Enter Total of lines 181 thru 193)	106,754,270	112,044,889
195	Maintenance		
196	(935) Maintenance of General Plant	16,564,426	16,597,732
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	123,318,696	128,642,621
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,364,995,013	1,315,782,142

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier’s service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	3 Bar G Wind Turbine #3 LLC	LU				
2	3 Bar G Wind Turbine #3 LLC	AD				
3	Avista Corp. WWP Division	OS				
4	Avista Nichols Pump	EX				
5	BIO ENERGY (Washington) LLC	LU				
6	Black Creek Hydro	LU				
7	Bloks Evergreen Dairy	LU				
8	Bonneville Power Admistration	OS				
9	BP Energy Co.	OS				
10	Brookfield Energy Marketing LP	OS				
11	California ISO	AD				
12	California ISO	OS				
13	California ISO - EIM Purchases	SF				
14	Calpine Energy Management	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Cascade Community Solar	LU				
2	Chelan County PUD #1	OS				
3	Chelan PUD - Rock Island and Rocky Reh	LF				
4	Citigroup Energy Inc	OS				
5	Citigroup Energy (Financial)	OS				
6	Clatskanie PUD	OS				
7	Clatskanie PUD	AD				
8	Conoco, Inc.	OS				
9	CP Energy Marketing (Epcor)	OS				
10	Douglas County PUD #1	OS				
11	Douglas PUD - Wells Project	LF				
12	Edaleen Dairy, LLC	LU				
13	EDF Trading (Financial)	OS				
14	EDF Trading NA LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Electron Hydro, LLC	LU				
2	Emerald City Renewables, LLC	LU				
3	Energy Keepers Inc.	OS				
4	Eugene Water & Electric	OS				
5	Exelon Generation Co LLC	OS				
6	Farm Power Lynden LLC	LU				
7	Farm Power Rexville LLC	LU				
8	Grant County PUD #2	OS				
9	Grant PUD - Priest Rapids Project	LF				
10	Gridforce Energy Management, LLC.	OS				
11	Iberdrola Renewables (Klondike Wind P)	AD				
12	Iberdrola Renewables (Klondike Wind P)	LU				
13	Iberdrola Renewables (PPM Energy)	AD				
14	Iberdrola Renewables (PPM Energy)	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Idaho Power Company	OS				
2	Ikea U.S. West, Inc.	LU				
3	Island Community Solar	LU				
4	Kingdom Energy Products (Sygitowicz)	LU				
5	Knudsen Wind Turbine#1	LU				
6	Koma Kulshan Associates	LU				
7	Lake Washington School District #414	LU				
8	Morgan Stanley CG	OS				
9	Morgan Stanley CG (Financial)	OS				
10	NextEra Energy Power Marketing	OS				
11	Northwestern Energy	OS				
12	Okanogan PUD	OS				
13	Pacific Gas & Elec - Exchange	EX				
14	Pacificorp	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Portland General Electric	OS				
2	Powerex (Point Roberts)	LF				
3	Powerex Corp.	OS				
4	Public Service of Colorado	OS				
5	Puget Sound Hydro (Nooksack)	LU				
6	Rainbow Energy Marketing	OS				
7	Rainer BioGas	LU				
8	Residential Exchange	AD				
9	Seattle City Light Marketing	OS				
10	Shell Energy (Coral Pwr)	AD				
11	Shell Energy (Coral Pwr)	OS				
12	Skookumchuck Hydro	LU				
13	Smith Creek Hydro	LU				
14	Snohomish County PUD #1	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier’s service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	South Fork II Associates(Weeks Falls)	LU				
2	Swauk Wind LLC	LU				
3	System Deviation	EX				
4	Tacoma Power	OS				
5	Talen Energy Marketing	AD				
6	Talen Energy Marketing	OS				
7	Tenaska Power Services Co.	OS				
8	The Energy Authority	OS				
9	The Energy Authority	AD				
10	Transalta Centralia Generation LLC	LF				
11	TransAlta Energy Marketing	OS				
12	TransCanada Energy Sales Ltd	OS				
13	Turlock Irrigation District	OS				
14	Twin Falls Hydro	LU				
	Total					

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Van Dyk S Holsteins	LU				
2	VanderHaak Dairy Digester	LU				
3	Vitol Inc.	OS				
4	Wells Fargo (Financial)	OS				
5	Western Area Power Association	OS				
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
185				21,628		21,628	1
					11	11	2
149,792				4,645,065		4,645,065	3
	28,488			640,897		640,897	4
1				73		73	5
11,824				1,068,686		1,068,686	6
23				1,456		1,456	7
814,569				17,751,305		17,751,305	8
228,575				4,202,541		4,202,541	9
1,400				83,070		83,070	10
					137	137	11
15,271				1,020,975		1,020,975	12
752,414				7,622,422		7,622,422	13
140,387				2,643,660		2,643,660	14
16,847,052	441,488	861,577		574,146,127	-44,768,401	529,377,726	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
29				1,895		1,895	1
88,348				4,113,581		4,113,581	2
2,247,424				58,888,935	32,667,164	91,556,099	3
1,141,683				31,427,470		31,427,470	4
				-142,980		-142,980	5
4,029				99,990		99,990	6
175					5,950	5,950	7
3,600				60,700		60,700	8
15,194				762,633		762,633	9
185,810				2,961,958		2,961,958	10
1,168,961				20,515,110		20,515,110	11
4,701				426,841		426,841	12
				1,817,488		1,817,488	13
224,706				7,478,681		7,478,681	14
16,847,052	441,488	861,577		574,146,127	-44,768,401	529,377,726	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
136,215				8,766,829		8,766,829	1
33,932				3,066,734		3,066,734	2
36,575				1,806,750		1,806,750	3
19,794				630,575		630,575	4
318,812				11,432,938		11,432,938	5
5,065				591,316		591,316	6
4,650				542,855		542,855	7
43				1,484		1,484	8
52,318				760,850		760,850	9
31				1,081		1,081	10
					9,626	9,626	11
119,259				7,592,895		7,592,895	12
-4					-115	-115	13
736,394				24,685,673		24,685,673	14
16,847,052	441,488	861,577		574,146,127	-44,768,401	529,377,726	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
22,841				408,790		408,790	1
64				4,133		4,133	2
60				5,445		5,445	3
697				44,821		44,821	4
119				13,868		13,868	5
41,921				3,438,796		3,438,796	6
261				23,477		23,477	7
213,562				6,507,195		6,507,195	8
				5,003,312		5,003,312	9
400				34,800		34,800	10
6,404				175,565		175,565	11
26,731				525,076		525,076	12
	413,000	413,000					13
70,973				1,943,663		1,943,663	14
16,847,052	441,488	861,577		574,146,127	-44,768,401	529,377,726	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
204,989				11,076,661		11,076,661	1
19,966				1,207,718		1,207,718	2
201,832				10,377,509		10,377,509	3
84,535				1,788,350		1,788,350	4
22,251				2,011,006		2,011,006	5
12,839				790,783		790,783	6
5,376				559,257		559,257	7
					-77,453,660	-77,453,660	8
125,919				4,153,757		4,153,757	9
					-400	-400	10
543,439				11,296,178		11,296,178	11
3,280				338,348		338,348	12
137				14,141		14,141	13
42,165				546,705		546,705	14
16,847,052	441,488	861,577		574,146,127	-44,768,401	529,377,726	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
14,576				1,093,190		1,093,190	1
11,707				1,058,108		1,058,108	2
		448,577					3
66,701				2,893,908		2,893,908	4
-107					-3,322	-3,322	5
106,200				2,024,562		2,024,562	6
369				4,797		4,797	7
693,619				21,990,885		21,990,885	8
					6,208	6,208	9
3,327,909				165,811,287		165,811,287	10
1,712,637				75,418,124		75,418,124	11
700				34,025		34,025	12
38,523				1,790,887		1,790,887	13
78,046				5,853,473		5,853,473	14
16,847,052	441,488	861,577		574,146,127	-44,768,401	529,377,726	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
992				102,364		102,364	1
3,598				420,004		420,004	2
478,633				12,150,422		12,150,422	3
				-6,783,389		-6,783,389	4
3				66		66	5
							6
							7
							8
							9
							10
							11
							12
							13
							14
16,847,052	441,488	861,577		574,146,127	-44,768,401	529,377,726	

Schedule Page: 326 Line No.: 1 Column: a
Contract Expires Dec, 2019
Schedule Page: 326 Line No.: 2 Column: a
Prior period adjustment
Schedule Page: 326 Line No.: 5 Column: a
Contract Expires Dec, 2021
Schedule Page: 326 Line No.: 6 Column: a
Contract Expires Dec, 2021
Schedule Page: 326 Line No.: 7 Column: a
Contract Expires Dec, 2031
Schedule Page: 326 Line No.: 8 Column: a
Contract Expires Sep, 2029
Schedule Page: 326 Line No.: 11 Column: a
Prior period adjustment
Schedule Page: 326.1 Line No.: 1 Column: a
Contract Expires Dec, 2026
Schedule Page: 326.1 Line No.: 3 Column: a
Contract Expires Oct, 2031
Schedule Page: 326.1 Line No.: 5 Column: a
Power Financial Hedging Transactions
Schedule Page: 326.1 Line No.: 7 Column: a
Prior period adjustment
Schedule Page: 326.1 Line No.: 11 Column: a
Contract Expires Sep, 2028
Schedule Page: 326.1 Line No.: 12 Column: a
Contract Expires Dec, 2021
Schedule Page: 326.1 Line No.: 13 Column: a
Power Financial Hedging Transactions
Schedule Page: 326.2 Line No.: 1 Column: a
Contract Expires Nov, 2024
Schedule Page: 326.2 Line No.: 2 Column: a
Contract Expires Dec, 2029
Schedule Page: 326.2 Line No.: 6 Column: a
Contract Expires Dec, 2019
Schedule Page: 326.2 Line No.: 7 Column: a
Contract Expires Dec, 2019
Schedule Page: 326.2 Line No.: 9 Column: a
Contract Expires Apr, 2052
Schedule Page: 326.2 Line No.: 11 Column: a
Prior period adjustment
Schedule Page: 326.2 Line No.: 12 Column: a
Contract Expires Nov, 2027
Schedule Page: 326.2 Line No.: 13 Column: a
Prior period adjustment
Schedule Page: 326.3 Line No.: 2 Column: a
Contract Expires Dec, 2031
Schedule Page: 326.3 Line No.: 3 Column: a
Contract Expires Dec, 2021
Schedule Page: 326.3 Line No.: 4 Column: a
Contract Expires Dec, 2030
Schedule Page: 326.3 Line No.: 5 Column: a

Contract Expires Dec, 2019

Schedule Page: 326.3 Line No.: 6 Column: a

Contract Expires Mar, 2037

Schedule Page: 326.3 Line No.: 7 Column: a

Contract Expires Dec, 2021

Schedule Page: 326.3 Line No.: 9 Column: a

Power Financial Hedging Transactions

Schedule Page: 326.4 Line No.: 2 Column: a

Contract Expires Sep, 2019

Schedule Page: 326.4 Line No.: 5 Column: a

Contract Expires Dec, 2021

Schedule Page: 326.4 Line No.: 7 Column: a

Contract Expires Dec, 2020

Schedule Page: 326.4 Line No.: 8 Column: a

Residential Exchange

Schedule Page: 326.4 Line No.: 10 Column: a

Prior period adjustment

Schedule Page: 326.4 Line No.: 12 Column: a

Contract Expires Dec, 2020

Schedule Page: 326.4 Line No.: 13 Column: a

Contract Expires Dec, 2020

Schedule Page: 326.5 Line No.: 1 Column: a

Contract Expires Nov, 2022

Schedule Page: 326.5 Line No.: 2 Column: a

Contract Expires Dec, 2021

Schedule Page: 326.5 Line No.: 5 Column: a

Prior period adjustment

Schedule Page: 326.5 Line No.: 9 Column: a

Prior period adjustment

Schedule Page: 326.5 Line No.: 10 Column: a

Contract Expires Dec, 2025

Schedule Page: 326.5 Line No.: 14 Column: a

Contract Expires Mar, 2025

Schedule Page: 326.6 Line No.: 1 Column: a

Contract Expires Dec, 2020

Schedule Page: 326.6 Line No.: 2 Column: a

Contract Expires Dec, 2019

Schedule Page: 326.6 Line No.: 4 Column: a

Power Financial Hedging Transactions

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Seattle City Light	Seattle City Light	Seattle City Light	OLF
2	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	OS
3	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	OLF
4	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	OLF
5	Tacoma City Light	Tacoma City Light	Tacoma City Light	OS
6				
7	Bonneville Power Administration	Bonneville Power Admin	City of Blaine	FNO
8	Bonneville Power Administration	Bonneville Power Admin	City of Sumas	FNO
9	Bonneville Power Administration	Bonneville Power Admin	Kittitas County PUD	FNO
10	Bonneville Power Administration	Bonneville Power Admin	Orcas Power & Light	FNO
11	Bonneville Power Administration	Bonneville Power Admin	Tanner Electric Cooperative	FNO
12	Bonneville Power Administration	Bonneville Power Admin	Tanner Electric Cooperative	FNO
13	Bonneville Power Administration	Bonneville Power Admin	Tanner Electric Cooperative	FNO
14	Bonneville Power Administration	Bonneville Power Admin	Port of Seattle and Various	FNO
15				
16	Morgan Stanley Capital	Various	Various	LFP
17	Powerex	Various	Various	LFP
18	Powerex	Various	Various	LFP
19	Sierra Pacific Industries	Various	Various	LFP
20	TransAlta Energy	Various	Various	LFP
21	Vantage Wind Energy LLC- Invenergy	Various	Various	LFP
22	Whatcom County PUD	Whatcom County PUD	Whatcom County PUD	LFP
23				
24	Brookfield Energy Marketing, LP	Various	Various	SFP
25	Avangrid Renewables, LLC	Various	Various	SFP
26	Macquarie Energy, LLC	Various	Various	SFP
27	Morgan Stanley Capital	Various	Various	SFP
28	Powerex	Various	Various	SFP
29	Shell Energy North America	Various	Various	SFP
30	Sierra Pacific Industries	Various	Various	SFP
31	Snohomish County PUD	Various	Various	SFP
32	Tacoma Power	Various	Various	SFP
33				
34	Avista	Various	Various	NF
	TOTAL			

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Brookfield Energy Marketing, LP	Various	Various	NF
2	Avangrid Renewables, LLC	Various	Various	NF
3	Macquarie Energy, LLC	Various	Various	NF
4	Morgan Stanley Capital	Various	Various	NF
5	Powerex	Various	Various	NF
6	Powerex	Various	Various	NF
7	Seattle City Light Marketing	Various	Various	NF
8	Shell Energy North America	Various	Various	NF
9	Shell Energy North America	Various	Various	NF
10	Sierra Pacific Industries	Various	Various	NF
11	Snohomish County PUD	Various	Various	NF
12	Tacoma Power	Various	Various	NF
13	Tacoma Power	Various	Various	NF
14	The Energy Authority	Various	Various	NF
15	TransAlta Energy	Various	Various	NF
16	Turlock Irrigation District	Various	Various	NF
17	Whatcom County PUD	Various	Various	NF
18				
19	Morgan Stanley Capital	Various	Various	AD
20	Powerex	Various	Various	AD
21				
22	Transportation Customers			
23	Air Liquide	Various	Air Liquide	FNO
24	Air Products	Various	Air Products	FNO
25	AMCOR Rigid Plastics USA	Various	AMCOR Rigid Plastics USA	FNO
26	Bellingham Cold Storage - Orchard	Various	Bellingham Cold Storage - Orchar	FNO
27	Bellingham Cold Storage - Roeder	Various	Bellingham Cold Storage - Roeder	FNO
28	Boeing	Various	Boeing	FNO
29	BP Westcoast Products	Various	BP Westcoast Products	FNO
30	Center Drive Owners	Various	Center Drive Owners	FNO
31	DBINTC, LLC	Various	DBINTC, LLC	FNO
32	Shell Oil Products (Equilon)	Various	Shell (Equilon)	FNO
33	Tesoro	Various	Tesoro	FNO
34				
	TOTAL			

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Air Liquide	Various	Air Liquide	AD
2	Air Products	Various	Air Products	AD
3	AMCOR Rigid Plastics USA	Various	AMCOR Rigid Plastics USA	AD
4	Avista	Various	Various	AD
5	Bellingham Cold Storage - Orchard	Various	Bellingham Cold Storage - Orchar	AD
6	Boeing	Various	Various	AD
7	Bonneville Power Administration	Various	Various	AD
8	BP Westcoast Products	Various	BP Westcoast Products	AD
9	Brookfield Energy Marketing, LP	Various	Various	AD
10	DBINTC, LLC	Various	Various	AD
11	Excelon Generation Company, LLC	Various	Various	AD
12	Intel	Various	Various	AD
13	Morgan Stanley Capital	Various	Various	AD
14	Powerex	Various	Various	AD
15	Shell Energy North America	Various	Various	AD
16	Shell Oil Products (Equilon)	Various	Shell (Equilon)	AD
17	Sierra Pacific Industries	Various	Various	AD
18	Tesoro	Various	Tesoro	AD
19	The Energy Authority	Various	Various	AD
20	TransAlta Energy	Various	Various	AD
21	Watcom County PUD	Watcom County PUD	Watcom County PUD	AD
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FRS #155	Stillwater Substn	Bothell Substation		58,266	58,266	1
FRS #60	Beverly Park Substn	Goldbar Substation				2
FRS #28	Beverly Park Substn	Hilton Lake Substn		78,986	78,986	3
FRS #28	Beverly Park Substn	Olympic Pipe Substn		9,368	9,368	4
FRS #62	Starwood Substation	Baldi Substation				5
						6
PSE OATT	Custer Substation	Blaine&Semiahmo Sub		81,445	81,445	7
PSE OATT	Bellingham Substn	City of Sumas Sub		33,752	33,752	8
PSE OATT	White River Substn	Teanaway Substation		17,927	17,927	9
PSE OATT	Murray Bellingham	Fidalgo Substation		221,338	221,338	10
PSE OATT	Maple Valley Substn	Ames Lake Tap		21,751	21,751	11
PSE OATT	Olympia Substation	Luhr Beach Tap		13,857	13,857	12
PSE OATT	Maple Valley Substn	North Bend Substn		64,873	64,873	13
PSE OATT	Various	Sea Tac Airport		145,127	145,127	14
						15
PSE OATT	John Day, COB	John Day, COB	100	876,000	876,000	16
PSE OATT	John Day, COB	John Day, COB	225	1,962,672	1,962,672	17
PSE OATT	Various Washington	Various Washington	90	788,400	788,400	18
PSE OATT	Various Washington	Various Washington	15	131,400	131,400	19
PSE OATT	John Day, COB	John Day, COB	75	657,000	657,000	20
PSE OATT	Various Washington	Various Washington				21
PSE OATT	Custer Substation	Enterprise Sub	2	17,520	17,520	22
						23
PSE OATT	John Day, COB	John Day, COB				24
PSE OATT	John Day, COB	John Day, COB	2,656	182,208	182,208	25
PSE OATT	John Day, COB	John Day, COB	381	31,608	31,608	26
PSE OATT	John Day, COB	John Day, COB				27
PSE OATT	Various Washington	Various Washington	2,238	232,584	232,584	28
PSE OATT	Various Washington	Various Washington	45	33,105	33,105	29
PSE OATT	Various Washington	Various Washington	32	23,304	23,304	30
PSE OATT	Various Washington	Various Washington	1,709	48,708	48,708	31
PSE OATT	John Day, COB	John Day, COB	10	240	240	32
						33
PSE OATT	John Day, COB	John Day, COB		9,447	9,447	34
			7,578	**7,963,863**	**7,963,863**	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
PSE OATT	John Day, COB	John Day, COB		29,997	29,997	1
PSE OATT	John Day, COB	John Day, COB		450	450	2
PSE OATT	John Day, COB	John Day, COB		2,339	2,339	3
PSE OATT	John Day, COB	John Day, COB		43,847	43,847	4
PSE OATT	John Day, COB	John Day, COB		17,283	17,283	5
PSE OATT	Various Washington	Various Washington		21,247	21,247	6
PSE OATT	John Day, COB	John Day, COB		1,920	1,920	7
PSE OATT	John Day, COB	John Day, COB		56,947	56,947	8
PSE OATT	Various Washington	Various Washington		6,624	6,624	9
PSE OATT	Various Washington	Various Washington		159	159	10
PSE OATT	Various Washington	Various Washington		5,541	5,541	11
PSE OATT	John Day, COB	John Day, COB		1,994	1,994	12
PSE OATT	Various Washington	Various Washington		1,185	1,185	13
PSE OATT	John Day, COB	John Day, COB		1,459	1,459	14
PSE OATT	John Day, COB	John Day, COB		4,781	4,781	15
PSE OATT	John Day, COB	John Day, COB		94	94	16
PSE OATT	Various Washington	Various Washington		1	1	17
						18
PSE OATT	Various Washington	Various Washington				19
PSE OATT	Various Washington	Various Washington				20
						21
						22
PSE OATT	Rocky Reach 115KV Sw	Air Liquide		72,398	72,398	23
PSE OATT	Rocky Reach 115KV Sw	Air Products		53,654	53,654	24
PSE OATT	Rocky Reach 115KV Sw	AMCOR Rigid Plastics		39,340	39,340	25
PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Orch		16,848	16,848	26
PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Roed		15,256	15,256	27
PSE OATT	Rocky Reach 115KV Sw	Boeing		456,423	456,423	28
PSE OATT	Rocky Reach 115KV Sw	BP Westcoast Product		763,574	763,574	29
PSE OATT	Rocky Reach 115KV Sw	Center Drive Owners				30
PSE OATT	Rocky Reach 115KV Sw	DBINTC, LLC		3,171	3,171	31
PSE OATT	Rocky Reach 115KV Sw	Equilon Refinery		345,291	345,291	32
PSE OATT	Rocky Reach 115KV Sw	Tesoro		261,154	261,154	33
						34
			7,578	**7,963,863**	**7,963,863**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
PSE OATT	Rocky Reach 115KV Sw	Air Liquide				1
PSE OATT	Rocky Reach 115KV Sw	Air Products				2
PSE OATT	Various Washington	Various Washington				3
PSE OATT	Various Washington	Various Washington				4
PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Orch				5
PSE OATT	Various Washington	Various Washington				6
PSE OATT	Various Washington	Various Washington				7
PSE OATT	Rocky Reach 115KV Sw	BP Westcoast Product				8
PSE OATT	Various Washingto	Various Washingto				9
PSE OATT	Rocky Reach 115KV Sw	DBINTC, LLC				10
PSE OATT	Various Washington	Various Washington				11
PSE OATT	Rocky Reach 115KV Sw	Intel				12
PSE OATT	Various Washington	Various Washington				13
PSE OATT	Various Washington	Various Washington				14
PSE OATT	Various Washington	Various Washington				15
PSE OATT	Various Washington	Various Washington				16
PSE OATT	Various Washington	Various Washington				17
PSE OATT	Various Washington	Various Washington				18
PSE OATT	Various Washington	Various Washington				19
PSE OATT	Various Washington	Various Washington				20
PSE OATT	Custer Substation	Enterprise Sub				21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			7,578	**7,963,863**	**7,963,863**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
333,976			333,976	1
		600	600	2
12,631		600	13,231	3
2,558		600	3,158	4
		4,576	4,576	5
				6
305,446		263,542	568,988	7
114,241		184,504	298,745	8
76,965		62,432	139,397	9
879,401		257,704	1,137,105	10
90,197		43,475	133,672	11
57,719		55,541	113,260	12
247,134		114,340	361,474	13
464,442		355,809	820,251	14
				15
1,428,650		376,374	1,805,024	16
3,201,862		849,430	4,051,292	17
2,337,402		2,075,840	4,413,242	18
389,676		185,808	575,484	19
1,071,488		401,902	1,473,390	20
654		27	681	21
51,957		19,133	71,090	22
				23
		69	69	24
300,169		124,275	424,444	25
52,436		19,976	72,412	26
		6,048	6,048	27
681,547		171,297	852,844	28
102,501		30,054	132,555	29
69,405		34,810	104,215	30
168,902		55,347	224,249	31
493		128	621	32
				33
	22,261	4,958	27,219	34
18,766,887	**549,461**	**9,743,005**	**29,059,353**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	61,305	14,940	76,245	1
	1,218	816	2,034	2
	5,673	1,677	7,350	3
	97,249	34,058	131,307	4
	47,923	14,542	62,465	5
	74,147	24,822	98,969	6
	5,402	1,577	6,979	7
	130,372	45,907	176,279	8
	26,989	24,855	51,844	9
	26,392	28,670	55,062	10
	26,338	11,792	38,130	11
	3,968	1,021	4,989	12
	4,584	852	5,436	13
	3,117	966	4,083	14
	12,194	4,602	16,796	15
	255	101	356	16
	74	82	156	17
				18
		-1,677	-1,677	19
		-1,689	-1,689	20
				21
				22
213,436		115,830	329,266	23
168,097		88,068	256,165	24
107,699		96,997	204,696	25
59,524		31,350	90,874	26
28,954		52,321	81,275	27
1,586,512		1,011,793	2,598,305	28
2,306,433		1,232,241	3,538,674	29
		747	747	30
10,818		8,152	18,970	31
1,043,874		693,006	1,736,880	32
799,688		530,143	1,329,831	33
				34
18,766,887	**549,461**	**9,743,005**	**29,059,353**	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		-395	-395	1
		-110	-110	2
		-244	-244	3
		-15	-15	4
		-192	-192	5
		-3,032	-3,032	6
		-4,564	-4,564	7
		-4,272	-4,272	8
		-2	-2	9
		-17	-17	10
		-4	-4	11
		-23	-23	12
		-4,688	-4,688	13
		-148	-148	14
		-138	-138	15
		-1,797	-1,797	16
		-8	-8	17
		-1,489	-1,489	18
		-11	-11	19
		-3,514	-3,514	20
		-93	-93	21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
18,766,887	**549,461**	**9,743,005**	**29,059,353**	

Schedule Page: 328 Line No.: 1 Column: d

Contract expires with three years written notice.

Schedule Page: 328 Line No.: 1 Column: e

Grandfathered Exchange and Transfer Agreement where power from Seattle City Light's (SCL) Tolt River South Fork project is transferred from Puget Sound Energy's Stillwater switching station to SCL's Bothell substation.

Schedule Page: 328 Line No.: 1 Column: h

Grandfathered Exchange and Transfer Agreement where power from Seattle City Light's (SCL) Tolt River South Fork project is transferred from Puget Sound Energy's Stillwater switching station to SCL's Bothell substation.

Schedule Page: 328 Line No.: 2 Column: e

Grandfathered Exchange and Transfer Agreement for service to Snohomish County PUD's Goldbar substation.

Schedule Page: 328 Line No.: 2 Column: h

Grandfathered Exchange and Transfer Agreement for service to Snohomish County PUD's Goldbar substation.

Schedule Page: 328 Line No.: 2 Column: m

Use of facilities charges.

Schedule Page: 328 Line No.: 3 Column: d

Contract expires with two years written notice.

Schedule Page: 328 Line No.: 3 Column: e

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Hilton Lake substation.

Schedule Page: 328 Line No.: 3 Column: h

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Hilton Lake substation.

Schedule Page: 328 Line No.: 3 Column: m

Use of facilities charges.

Schedule Page: 328 Line No.: 4 Column: d

Contract expires with two years written notice.

Schedule Page: 328 Line No.: 4 Column: e

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Olympic Pipe substation.

Schedule Page: 328 Line No.: 4 Column: h

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Olympic Pipe substation.

Schedule Page: 328 Line No.: 4 Column: m

Use of facilities charges.

Schedule Page: 328 Line No.: 5 Column: d

Use of facilities on pre-888 contract with Baldi substation.
Contract expires every 10 years but is automatically renewed unless otherwise requested.

Schedule Page: 328 Line No.: 5 Column: e

Grandfathered Transfer Agreement with the City of Tacoma where Puget Sound Energy transfers transmission and energy to Tacoma's North Fork Well Field Complex.

Schedule Page: 328 Line No.: 5 Column: h

Grandfathered Transfer Agreement with the City of Tacoma where Puget Sound Energy transfers transmission and energy to Tacoma's North Fork Well Field Complex.

Schedule Page: 328 Line No.: 5 Column: m

Use of facilities charges.

Schedule Page: 328 Line No.: 7 Column: e

Full title of the FERC rate is FERC Electric Tariff of Puget Sound Energy, Inc. filed with the Federal Energy Regulatory Commission, Open Access Transmission Tariff.

Schedule Page: 328 Line No.: 7 Column: h

Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.

Schedule Page: 328 Line No.: 7 Column: m

Includes ancillary services, Wahsington State tax, facilities fees, and loss return charges.

Schedule Page: 328 Line No.: 8 Column: h

Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.

Schedule Page: 328 Line No.: 8 Column: m

Includes ancillary services, Wahsington State tax, facilities fees, and loss return charges.

Schedule Page: 328 Line No.: 9 Column: h

Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.

Schedule Page: 328 Line No.: 9 Column: m

Includes ancillary services, Wahsington State tax, facilities fees, and loss return charges.

Schedule Page: 328 Line No.: 10 Column: h

Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.

Schedule Page: 328 Line No.: 10 Column: m

Includes ancillary services, Wahsington State tax, and loss return charges.

Schedule Page: 328 Line No.: 11 Column: h

Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.

Schedule Page: 328 Line No.: 11 Column: m

Includes ancillary services, Wahsington State tax, and loss return charges.

Schedule Page: 328 Line No.: 12 Column: h

Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.

Schedule Page: 328 Line No.: 12 Column: m

Includes ancillary services, Wahsington State tax, facilities fees, and loss return charges.

Schedule Page: 328 Line No.: 13 Column: h

Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.

Schedule Page: 328 Line No.: 13 Column: m

Includes ancillary services, Wahsington State tax, and loss return charges.

Schedule Page: 328 Line No.: 14 Column: h

Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.

Schedule Page: 328 Line No.: 14 Column: m

Includes ancillary services, Wahsington State tax, facilities fees, and loss return charges.

Schedule Page: 328 Line No.: 16 Column: d

Contract expires on August 1, 2020.

Schedule Page: 328 Line No.: 16 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328 Line No.: 17 Column: d

Powerex LFP 225 MW

Includes three contracts with the following end dates:

25 MW – October 1, 2022
100 MW – September 1, 2018
100 MW – September 1, 2019

Schedule Page: 328 Line No.: 17 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328 Line No.: 18 Column: a

Long-Term, point-to-point transmission resale.

Schedule Page: 328 Line No.: 18 Column: d

Contract expires on October 1, 2020.

Schedule Page: 328 Line No.: 18 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328 Line No.: 19 Column: d

Contract expires on December 1, 2021.

Schedule Page: 328 Line No.: 19 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328 Line No.: 20 Column: d

Contract expire on October 1, 2022, and January 1, 2022.

Schedule Page: 328 Line No.: 20 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328 Line No.: 21 Column: d

Contract expires on October 1, 2020.

Schedule Page: 328 Line No.: 21 Column: h

90 MW long-term contract resold to Powerex.

Schedule Page: 328 Line No.: 21 Column: m

Includes ancillary services, and Washington State tax.

Schedule Page: 328 Line No.: 22 Column: d

Contract expires with one year written notice.

Schedule Page: 328 Line No.: 22 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328 Line No.: 24 Column: m

Includes ancillary services.

Schedule Page: 328 Line No.: 25 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328 Line No.: 26 Column: a

Macquarie Energy, LLC is an affiliate of Puget Sound Energy.

Schedule Page: 328 Line No.: 26 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328 Line No.: 27 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328 Line No.: 28 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328 Line No.: 29 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328 Line No.: 30 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328 Line No.: 31 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328 Line No.: 32 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328 Line No.: 34 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328.1 Line No.: 1 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328.1 Line No.: 2 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328.1 Line No.: 3 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328.1 Line No.: 4 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328.1 Line No.: 5 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328.1 Line No.: 6 Column: m

Includes ancillary services, Washington State tax, and loss return charges. Also includes unreserved use charges.

Schedule Page: 328.1 Line No.: 7 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328.1 Line No.: 8 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328.1 Line No.: 9 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328.1 Line No.: 10 Column: m

Includes ancillary services, and Washington State tax. Also, includes unreserved use charges.

Schedule Page: 328.1 Line No.: 11 Column: m

Includes ancillary services, Washington State tax, and loss return charges. Also includes unreserved use charges.

Schedule Page: 328.1 Line No.: 12 Column: m

Includes ancillary services, and loss return.

Schedule Page: 328.1 Line No.: 13 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328.1 Line No.: 14 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328.1 Line No.: 15 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328.1 Line No.: 16 Column: m

Includes ancillary services, and loss return charges.

Schedule Page: 328.1 Line No.: 17 Column: m

Includes ancillary services, and Washington State tax. Also, includes unreserved use charges.

Schedule Page: 328.1 Line No.: 19 Column: m

Prior period adjustment.

Schedule Page: 328.1 Line No.: 20 Column: m

Prior period adjustment.

Schedule Page: 328.1 Line No.: 23 Column: d

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.1 Line No.: 23 Column: f

Full name of the point of receipt is Rocky Reach 115KV switchyard.

Schedule Page: 328.1 Line No.: 23 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328.1 Line No.: 24 Column: d

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.1 Line No.: 24 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328.1 Line No.: 25 Column: d

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.1 Line No.: 25 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328.1 Line No.: 26 Column: d

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.1 Line No.: 26 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328.1 Line No.: 27 Column: d

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.1 Line No.: 27 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328.1 Line No.: 28 Column: d

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.1 Line No.: 28 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328.1 Line No.: 29 Column: d

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.1 Line No.: 29 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328.1 Line No.: 30 Column: d

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.1 Line No.: 30 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328.1 Line No.: 31 Column: d

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.1 Line No.: 31 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328.1 Line No.: 32 Column: d

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.1 Line No.: 32 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328.1 Line No.: 33 Column: d

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.1 Line No.: 33 Column: m

Includes ancillary services, Washington State tax, and loss return charges.

Schedule Page: 328.2 Line No.: 1 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 2 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 3 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 4 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 5 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 6 Column: m

Distribution of prior year unreserved use penalty charges.

Name of Respondent Puget Sound Energy, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report 2018/Q4

FOOTNOTE DATA

Schedule Page: 328.2 Line No.: 7 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 8 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 9 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 10 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 11 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 12 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 13 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 14 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 15 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 16 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 17 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 18 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 19 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 20 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 21 Column: m

Distribution of prior year unreserved use penalty charges.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Pwr Admin	LFP			18,496,084		3,213,560	21,709,644
2	Bonneville Pwr Admin	LFP	4,501,868	4,501,868	64,248,402		12,495,842	76,744,244
3	Bonneville Pwr Admin	SFP			45,148		7,738	52,886
4	Bonneville Pwr Admin	NF	2,869	2,869	141,000	12,136	2,800	155,936
5	Bonneville Pwr Admin	OS					110,600	110,600
6	Bonneville Pwr Admin	OS					6,022,498	6,022,498
7	Bonneville Pwr Admin	OS					6,891,176	6,891,176
8	Bonneville Pwr Admin	AD					97,606	97,606
9	Avista Corp	NF	26,152	26,152		79,797		79,797
10	Avista Corp	OS					-256	-256
11	Brookfield Enegy Mrktng	OS					-10,880	-10,880
12	Chelan County PUD No. 1	OLF	2,367,842	2,367,842			4,660,134	4,660,134
13	EDFT Trading NA, LLC	OS					-600	-600
14	Grant County PUD No. 2	OS					146,952	146,952
15	Iberdrola Renewables	OS					-196,672	-196,672
16	Idaho Power Company	OS					-60,682	-60,682
	TOTAL		8,089,762	8,089,762	83,077,490	264,949	32,465,339	115,807,778

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Klickitat PUD	LFP	1,115,147	1,115,147			1,307,725	1,307,725
2	Klondike Wind Power III	OS					367,045	367,045
3	Morgan Stanley CG	OS					-1,427,355	-1,427,355
4	Northwestern Energy	SFP	33,840	33,840	146,856		7,614	154,470
5	Northwestern Energy	NF	39,285	39,285		170,104	9,019	179,123
6	Northwestern Energy	OS					415,403	415,403
7	Northwestern Energy	AD					-5,082	-5,082
8	Pacificorp	OS					-29,600	-29,600
9	Pacificorp	AD					-181	-181
10	Portland General Elec	NF	2,759	2,759		2,912		2,912
11	Powerex	OS					-1,039,307	-1,039,307
12	Tacoma Power	OS					-7,500	-7,500
13	The Energy Authority	OS					-208,682	-208,682
14	TransAlta Energy Mrktng	OS					439,358	439,358
15	TransAlta Energy Mrktng	OS					-750,281	-750,281
16	Whatcom Co PUD #1	OS					7,347	7,347
	TOTAL		8,089,762	8,089,762	83,077,490	264,949	32,465,339	115,807,778

Schedule Page: 332 Line No.: 1 Column: b

Includes a contract with an end date of August 2018 and a contract wth several tables with end dates ranging from October 2017 to June 2037.

Schedule Page: 332 Line No.: 2 Column: b

Includes a contract with a calculated end date of mid-2017 and a contract with several tables with end dates ranging from February 2019 to August 2028.

Schedule Page: 332 Line No.: 12 Column: b

Contract end date is October 31, 2031.

Schedule Page: 332.1 Line No.: 1 Column: b

Contract end date is June 2032.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	779,569
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Western Electric Coordinator Council Dues	
7	Board of Director Fees & Expenses	802,540
8	Other Membership Dues	314,021
9	Communication Services	
10	Treasury Fees & Expenses	242,977
11	Misc General Expense - Electric	3,253,369
12	State/Fed Govt Related Industry Expenses	20,563
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	5,413,039

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			14,521,241		14,521,241
2	Steam Production Plant	44,708,149	4,333,887			49,042,036
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	19,178,479		1,185,284		20,363,763
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	75,071,046	3,225,082			78,296,128
7	Transmission Plant	34,137,063	83,378			34,220,441
8	Distribution Plant	130,302,863	64,714			130,367,577
9	Regional Transmission and Market Operation					
10	General Plant	13,040,021				13,040,021
11	Common Plant-Electric	17,320,738	1,381	43,970,126		61,292,245
12	TOTAL	333,758,359	7,708,442	59,676,651		401,143,452

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	WUTC Filing Fee	4,669,752		4,669,752	
2					
3	Federal fees:				
4	Upper & Lower Baker Project	1,337,426		1,337,426	
5	Snoqualmie 1 & 2 Project	112,524		112,524	
6	FERC Regulatory Comm Trading	744,355		744,355	
7					
8	Other Charges:				
9	FERC Regulatory Legal Fees		62,635	62,635	
10	State Regulatory Legal Fees		203,588	203,588	
11	Transmission Rate Case		143,332	143,332	
12	General Rate Case Legal Fees		91,937	91,937	
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	6,864,057	501,492	7,365,549	

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Electric	928	4,669,752					1
							2
							3
Electric	928	1,337,426					4
Electric	928	112,524					5
Electric	928	744,355					6
							7
							8
Electric	928	62,635					9
Electric	928	203,588					10
Electric	928	143,332					11
Electric	928	91,937					12
							13
							14
							15
							16
							17
							18
							19
							20
							21
							22
							23
							24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		7,365,549					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	Note: No R&D Activity for 2018	
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	22,170,771		
4	Transmission	6,996,178		
5	Regional Market			
6	Distribution	18,395,117		
7	Customer Accounts	10,677,889		
8	Customer Service and Informational	1,326,330		
9	Sales	652,518		
10	Administrative and General	27,966,885		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	88,185,688		
12	Maintenance			
13	Production	5,267,204		
14	Transmission	2,186,840		
15	Regional Market			
16	Distribution	8,999,920		
17	Administrative and General	396,743		
18	TOTAL Maintenance (Total of lines 13 thru 17)	16,850,707		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	27,437,975		
21	Transmission (Enter Total of lines 4 and 14)	9,183,018		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	27,395,037		
24	Customer Accounts (Transcribe from line 7)	10,677,889		
25	Customer Service and Informational (Transcribe from line 8)	1,326,330		
26	Sales (Transcribe from line 9)	652,518		
27	Administrative and General (Enter Total of lines 10 and 17)	28,363,628		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	105,036,395	830,782	105,867,177
29	Gas			
30	Operation			
31	Production-Manufactured Gas	87,900		
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	2,072,519		
34	Storage, LNG Terminaling and Processing	943,766		
35	Transmission			
36	Distribution	19,538,581		
37	Customer Accounts	8,086,204		
38	Customer Service and Informational	851,814		
39	Sales	-169,799		
40	Administrative and General	13,984,687		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	45,395,672		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	263,038		
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	6,077,826		
49	Administrative and General	225,390		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	6,566,254		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	87,900		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	2,072,519		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	1,206,804		
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	25,616,407		
58	Customer Accounts (Line 37)	8,086,204		
59	Customer Service and Informational (Line 38)	851,814		
60	Sales (Line 39)	-169,799		
61	Administrative and General (Lines 40 and 49)	14,210,077		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	51,961,926	410,992	52,372,918
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	156,998,321	1,241,774	158,240,095
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	64,330,052	508,817	64,838,869
69	Gas Plant	21,483,356	169,922	21,653,278
70	Other (provide details in footnote):	43,990,532	347,942	44,338,474
71	TOTAL Construction (Total of lines 68 thru 70)	129,803,940	1,026,681	130,830,621
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,874,170	22,733	2,896,903
74	Gas Plant	1,391,088	11,003	1,402,091
75	Other (provide details in footnote):	289,633	2,291	291,924
76	TOTAL Plant Removal (Total of lines 73 thru 75)	4,554,891	36,027	4,590,918
77	Other Accounts (Specify, provide details in footnote):	20,194,723	159,730	20,354,453
78				
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	20,194,723	159,730	20,354,453
96	TOTAL SALARIES AND WAGES	311,551,875	2,464,212	314,016,087

Schedule Page: 354 Line No.: 77 Column: a

Schedule Page: 354 Line No.: 77 Column: (a)

Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
Other Accounts (Specify):	20,194,723	159,730	20,354,453
121 Non Utility Property	38,139	302	38,441
163 Store Expense	3,571,017	28,245	3,599,262
182 Regulatory Asset	11,188,950	88,499	11,277,449
185 Temporary Facilities	27,910	221	28,131
149 Misc. Deferred Debits	0	0	0
186 Misc. Deferred Debits	3,763,199	29,765	3,792,964
Misc. 400 Accounts	1,604,070	12,687	1,616,757
143 Accts Receivable Misc.	0	0	0
Prelim Survey OG 183	0	0	0
Misc. 200 Accounts	1,438	11	1,449
Jackson Prairie Joint Venture - Capital - PSE Share	0	0	0
Jackson Prairie Joint Venture - Expense - PSE Share	0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

1 & 2 Common Plant and Accumulated Provision for Depreciation:

ACCOUNT	DESCRIPTION	BOOK VALUE 12/31/2018	ACCUMULATED PROVISION FOR DEPR & AMORT
C302	Franchises	2,512,785	41,127
C303	Software Development	482,194,897	134,588,818
C389	Land and Land Rights	53,468,868	2,210,087
C390	Structures and Improvements	201,904,351	77,429,560
C391	Office Furniture and Equipment	135,228,026	42,044,068
C392	Transportation Equipment	7,027,828	4,853,004
C393	Stores Equipment	92,576	43,822
C394	Tools/Shop/Garage Equipment	1,515,058	1,167,020
C396	Power Operated Equipment	726,509	1,082,508
C397	Communication Equipment	86,157,231	19,506,273
C398	Miscellaneous Equipment	1,057,960	1,547,222
C399	Other Tangible Property	501,177	2,106
Total Common Plant in Service		972,387,263	284,515,615

Common plant balances are not allocated to electric or Gas departments.

3. Common expense allocated to Electric and Gas Department:

Account	Description	Total	Allocated to Electric	Allocated to Gas	Allocated Basis
403	Depreciation	26,407,591	17,320,739	9,086,852	(D)
404	Amortization of LTD Term Plant	67,037,850	43,970,126	23,067,724	(D)
901	Customer Accounts and Collection Supervision	225,454	130,944	94,510	(A)
902	Meter Reading Expense	1,481,684	927,386	554,298	(B)
903	Customer Records and Collections	37,903,104	22,014,123	15,888,981	(A)
904	Uncollectible Accounts	6,637	4,353	2,284	(D)
908	Customer Assistance	1,163,430	675,720	487,710	(A)
909	Information and Instructional Advertising	2,088,370	1,212,925	875,445	(A)
910	Miscellaneous Customer Services and Information	1,538	893	645	(A)

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

912	Common Sales	(510,279)	(296,370)	(213,909)	(A)
920	Administrative and General Salaries	79,114,702	51,891,333	27,223,369	(D)
921	Office Supplies & Expense	224,803	147,448	77,355	(D)
922	Administrative Expense Transferred	(32,570,569)	(21,363,036)	(11,207,533)	(D)
923	Outside Services Employed	14,985,473	9,828,972	5,156,501	(D)
924	Property Insurance	16,481	9,988	6,494	(C)
925	Injuries & Damages	6,394,275	3,713,795	2,680,480	(A)
928	Regulatory Commission	314,640	206,372	108,268	(D)
930.2	Miscellaneous General Expense	7,106,542	4,661,181	2,445,361	(D)
931	Rents	10,035,672	6,582,397	3,453,275	(D)
935	Maintenance of General Plant	23,634,912	15,502,138	8,132,773	(D)
Total Expense		151,616,869	95,850,563	55,766,306	

(A) 12 Month Average Number of Customers
(B) Joint Meter Reading Customers
(C) Non-Production Plant
(D) 4-Factor Allocator (25% each: customer counts, direct labor O&M, classified plant and T&D expense excluding labor) Electric: 66.77%, and Gas: 33.23%

4. Docket UE-960195 of the Washington Utilities and Transportation Commission, dated February 5, 1997.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	540,845	1,935,266	5,707,069	8,585,326
3	Net Sales (Account 447)	(4,349,559)	(7,224,861)	(13,151,392)	(18,333,021)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	(3,808,714)	(5,289,595)	(7,444,323)	(9,747,695)

Schedule Page: 397 Line No.: 2 Column: e

	Q1, 2018	**Q2, 2018**	**Q3, 2018**	**Q4, 2018**	**YTD Total**
EIM Purchases	$ 534,965	$ 1,379,278	$ 2,986,488	$ 2,721,692	$ 7,622,423
Intertie Purchases	5,880	15,143	785,315	156,565	962,903
Total by Quarter	**$ 540,845**	**$ 1,394,421**	**$ 3,771,803**	**$ 2,878,257**	**$ 8,585,326**

Schedule Page: 397 Line No.: 3 Column: e

All sales are attributable to EIM participation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year — Usage - Related Billing Determinant — Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year — Usage - Related Billing Determinant — Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch				77,985	MW	5,141,814
2	Reactive Supply and Voltage				19,025	MW	139,411
3	Regulation and Frequency Response				5,360	MW	2,155,520
4	Energy Imbalance	464,477		10,429,004	413,295	MWh	8,940,436
5	Operating Reserve - Spinning	1,444,277		652,205	5,968	MW	765,985
6	Operating Reserve - Supplement	1,444,277		541,486	5,968	MW	745,285
7	Other	10,610		4,905	-8,665	MWh	-6,311,253
8	Total (Lines 1 thru 7)	3,363,641		11,627,600	518,936		11,577,198

Schedule Page: 398 Line No.: 1 Column: b

Schedule 1 purchases can be broken down as follows:

Number of Units	Unit of measure	Dollars
121,225	MW	$ 21,602,376
11,187	MWh	10,404
		$ 21,612,780

Schedule Page: 398 Line No.: 1 Column: e

Units for column e, lines 1, 2, 3, 5 and 6 have been calculated to a normalized MW/month based on the dollars billed since actual billings are based on a number of different units (kW/year, kW/month, kW/week, kW/day and kWh.)

Schedule Page: 398 Line No.: 2 Column: b

Schedule 2 purchases can be broken down as follows:

Number of Units	Unit of measure	Dollars
62,265	MW	$ 50,239
11,187	MWh	-
		$ 50,239

The units include reactive supply and voltage received from Bonneville Power Administration for which the rate is currently zero.

Schedule Page: 398 Line No.: 2 Column: e

Units for column e, lines 1, 2, 3, 5 and 6 have been calculated to a normalized MW/month based on the dollars billed since actual billings are based on a number of different units (kW/year, kW/month, kW/week, kW/day and kWh.)

Schedule Page: 398 Line No.: 3 Column: e

Sales can be broken down as follows:

Schedule 3 - Units: 3,940 MW Dollars: $ 452,303
Schedule 13 - Units: 1,420 MW Dollars: $ 1,703,217

Units for column e, lines 1, 2, 3, 5 and 6 have been calculated to a normalized MW/month based on the dollars billed since actual billings are based on a number of different units (kW/year, kW/month, kW/week, kW/day and kWh.)

Schedule Page: 398 Line No.: 5 Column: e

Units for column e, lines 1, 2, 3, 5 and 6 have been calculated to a normalized MW/month based on the dollars billed since actual billings are based on a number of different units (kW/year, kW/month, kW/week, kW/day and kWh.)

Schedule Page: 398 Line No.: 6 Column: e

Units for column e, lines 1, 2, 3, 5 and 6 have been calculated to a normalized MW/month based on the dollars billed since actual billings are based on a number of different units (kW/year, kW/month, kW/week, kW/day and kWh.)

Schedule Page: 398 Line No.: 7 Column: b

Schedule 9, Generator Imbalance, is reported in "Other" purchases on line 7. Also includes wind integration amounts.

Schedule Page: 398 Line No.: 7 Column: e

Schedule 9, Generator Imbalance, is reported in "Other" sales on line 7.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: WA Area Facilities

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	5,271	2	1800	3,741	337	1,150	43	232	123
2	February	5,521	23	800	3,975	360	1,150	36	228	308
3	March	4,993	7	800	3,470	340	1,150	33	228	124
4	Total for Quarter 1				11,186	1,037	3,450	112	688	555
5	April	5,728	2	800	3,212	336	1,150	30	335	207
6	May	4,188	14	1800	2,771	237	1,150	30	305	202
7	June	4,775	20	1800	2,989	319	1,150	317	234	22
8	Total for Quarter 2				8,972	892	3,450	377	874	431
9	July	5,029	30	1800	3,224	326	1,150	329	231	196
10	August	5,050	8	1800	3,240	329	1,150	331	656	75
11	September	4,459	6	1800	2,671	310	1,150	328	231	184
12	Total for Quarter 3				9,135	965	3,450	988	1,118	455
13	October	4,376	22	800	2,871	327	1,150	28	231	192
14	November	4,968	19	800	3,444	343	1,150	31	237	236
15	December	5,458	7	800	3,926	351	1,150	31	276	175
16	Total for Quarter 4				10,241	1,021	3,450	90	744	603
17	Total Year to Date/Year				39,534	3,915	13,800	1,567	3,424	2,044

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: Southern Intertie

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	700					400	300		
2	February	700					400	300		
3	March	400	8				400		10	
4	Total for Quarter 1						1,200	600	10	
5	April	400					400			
6	May	400					400			
7	June	700					400	300		
8	Total for Quarter 2						1,200	300		
9	July	700					400	300	75	
10	August	700					400	300	300	
11	September	700	19				400	300	100	
12	Total for Quarter 3						1,200	900	475	
13	October	400					400		306	
14	November	700					400	300		
15	December	700					400	300	6	
16	Total for Quarter 4						1,200	600	312	
17	Total Year to Date/Year						4,800	2,400	797	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: Colstrip

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	663					663			
2	February	663					663			
3	March	663					663			
4	Total for Quarter 1						1,989			
5	April	663					663			
6	May	663					663			
7	June	663					663			
8	Total for Quarter 2						1,989			
9	July	663					663			
10	August	663					663			
11	September	663					663			
12	Total for Quarter 3						1,989			
13	October	663					663			
14	November	663					663			
15	December	663					663			
16	Total for Quarter 4						1,989			
17	Total Year to Date/Year						7,956			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	6,634			3,741	337	2,213	343	232	123
2	February	6,884			3,975	360	2,213	336	228	308
3	March	6,056			3,470	340	2,213	33	238	124
4	Total for Quarter 1				11,186	1,037	6,639	712	698	555
5	April	5,791			3,212	336	2,213	30	335	207
6	May	5,251			2,771	237	2,213	30	305	202
7	June	6,138			2,989	319	2,213	617	234	22
8	Total for Quarter 2				8,972	892	6,639	677	874	431
9	July	6,392			3,224	326	2,213	629	306	196
10	August	6,413			3,240	329	2,213	631	956	75
11	September	5,822			2,671	310	2,213	328	331	184
12	Total for Quarter 3				9,135	965	6,639	1,588	1,593	455
13	October	5,439			2,871	327	2,213	28	537	192
14	November	6,331			3,444	343	2,213	331	237	236
15	December	6,821			3,926	351	2,213	331	282	175
16	Total for Quarter 4				10,241	1,021	6,639	690	1,056	603
17	Total Year to Date/Year				39,534	3,915	26,556	3,667	4,221	2,044

Schedule Page: 400 Line No.: 1 Column: j

Other Service (j) represents the total MWHr of EIM Transfer utilizing ATC (PSE OATT, Attachment O, section 5.3) for the day and hour of the monthly peak.

Schedule Page: 400.1 Line No.: 1 Column: c

Day and Hour of Monthly Peak were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours.

Schedule Page: 400.1 Line No.: 1 Column: d

Hour of Monthly Peak were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

Schedule Page: 400.2 Line No.: 1 Column: c

Day and Hour of Monthly Peak were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	20,697,196
3	Steam	5,408,532			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	7,084
5	Hydro-Conventional	914,540			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,377,547
7	Other	4,861,155			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	11,184,227	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	264,876
10	Purchases	16,847,052	27	Total Energy Losses	1,264,487
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	27,611,190
12	Received	441,488			
13	Delivered	861,577			
14	Net Exchanges (Line 12 minus line 13)	-420,089			
15	Transmission For Other (Wheeling)				
16	Received	7,963,863			
17	Delivered	7,963,863			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	27,611,190			

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	2,457,418	242,151	3,954	2	1800
30	February	2,542,770	477,872	4,206	23	0800
31	March	2,489,604	427,190	3,675	7	0700
32	April	2,095,252	327,174	3,421	2	0800
33	May	1,924,598	331,537	2,885	14	1800
34	June	1,965,326	399,374	3,161	20	1800
35	July	2,375,902	626,348	3,407	30	1800
36	August	2,303,815	593,883	3,423	8	1800
37	September	2,180,971	637,235	2,827	6	1800
38	October	2,137,550	366,572	3,040	22	0800
39	November	2,268,162	323,747	3,644	19	0800
40	December	2,869,823	624,436	4,132	6	0800
41	TOTAL	27,611,191	5,377,519			

Schedule Page: 401 Line No.: 29 Column: b

NAME OF SYSTEM: Point Roberts Transfer Point
2018

Line No.	Month (a)	Total Monthly Energy (MWH) (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (see instr 4) (d)	Day of Month (e)	Hour (f)
1	January	2,407		5.1	1	1000
2	February	2,248		5.1	22	0800
3	March	2,086		4.0	5	0800
4	**Total**	**6,741**	**0**			
5	April	1,586		3.6	1	0900
6	May	1,176		2.6	21	1000
7	June	1,133		2.5	30	2000
8	**Total**	**3,895**	**0**			
9	July	1,258		2.5	1	1000
10	August	1,266		2.4	26	1000
11	September	1,180		2.5	2	1000
12	**Total**	**3,704**	**0**			
13	October	1,494		3.0	14	0800
14	November	1,828		3.9	11	0900
15	December	2,303		5.2	21	2300
16	**Total**	**5,625**	**0**			
17	**Yr Total**	**19,965**	**0**			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *COLSTRIP 1 & 2* (b)			Plant Name: *COLSTRIP 3 & 4* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor			Semi-Outdoor		
3	Year Originally Constructed	1975			1984		
4	Year Last Unit was Installed	1976			1986		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	377.00			433.50		
6	Net Peak Demand on Plant - MW (60 minutes)	346			434		
7	Plant Hours Connected to Load	6838			8287		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	307			370		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	1767119000			2417831000		
13	Cost of Plant: Land and Land Rights	1006168			2788807		
14	Structures and Improvements	44798783			128152606		
15	Equipment Costs	274737613			402302535		
16	Asset Retirement Costs	46424524			44142592		
17	Total Cost	366967088			577386540		
18	Cost per KW of Installed Capacity (line 17/5) Including	973.3875			1331.9182		
19	Production Expenses: Oper, Supv, & Engr	123861			100751		
20	Fuel	42274502			37059689		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	3613003			2820886		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	188987			150094		
26	Misc Steam (or Nuclear) Power Expenses	6767855			4470720		
27	Rents	17677			53436		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	839578			602825		
30	Maintenance of Structures	581723			771780		
31	Maintenance of Boiler (or reactor) Plant	4396255			5616256		
32	Maintenance of Electric Plant	3255229			2816058		
33	Maintenance of Misc Steam (or Nuclear) Plant	1482742			1010949		
34	Total Production Expenses	63541412			55473444		
35	Expenses per Net KWh	0.0360			0.0229		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal			Coal		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons			Tons		
38	Quantity (Units) of Fuel Burned	1138012	0	0	1545484	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8636	0	0	8484	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	35.991	0.000	0.000	21.378	0.000	0.000
41	Average Cost of Fuel per Unit Burned	37.148	0.000	0.000	23.979	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.151	0.000	0.000	1.413	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.024	0.000	0.000	0.015	0.000	0.000
44	Average BTU per KWh Net Generation	11123.044	0.000	0.000	10845.991	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *MINT FARM* (b)			Plant Name: *SUMAS* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Outdoor		
3	Year Originally Constructed	2007			1993		
4	Year Last Unit was Installed	2007			1993		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	319.00			145.00		
6	Net Peak Demand on Plant - MW (60 minutes)	328			134		
7	Plant Hours Connected to Load	5341			2611		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	297			127		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	15			14		
12	Net Generation, Exclusive of Plant Use - KWh	1362895400			272158515		
13	Cost of Plant: Land and Land Rights	1194000			795165		
14	Structures and Improvements	11976018			5691608		
15	Equipment Costs	98710931			79277133		
16	Asset Retirement Costs	0			0		
17	Total Cost	111880949			85763906		
18	Cost per KW of Installed Capacity (line 17/5) Including	350.7240			591.4752		
19	Production Expenses: Oper, Supv, & Engr	375818			316376		
20	Fuel	39809312			8077614		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	152179			437333		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2374208			2135963		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	15313			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	65795			63208		
30	Maintenance of Structures	262828			129851		
31	Maintenance of Boiler (or reactor) Plant	942495			675813		
32	Maintenance of Electric Plant	2593136			785358		
33	Maintenance of Misc Steam (or Nuclear) Plant	113757			14868		
34	Total Production Expenses	46704841			12636384		
35	Expenses per Net KWh	0.0343			0.0464		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf			Mcf		
38	Quantity (Units) of Fuel Burned	9038582	0	0	2104418	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1100897	0	0	1100897	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.404	0.000	0.000	3.838	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.404	0.000	0.000	3.838	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.001	0.000	0.000	3.487	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.029	0.000	0.000	0.030	0.000	0.000
44	Average BTU per KWh Net Generation	7301.036	0.000	0.000	8512.494	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *FREDONIA 1&2* (b)			Plant Name: *FREDONIA 3&4* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Gas Turbine			Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Outdoor			Outdoor
3	Year Originally Constructed			1984			2001
4	Year Last Unit was Installed			1984			2001
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			258.20			117.80
6	Net Peak Demand on Plant - MW (60 minutes)			205			95
7	Plant Hours Connected to Load			1390			272
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			207			107
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			5			4
12	Net Generation, Exclusive of Plant Use - KWh			120332800			9119500
13	Cost of Plant: Land and Land Rights			1502988			0
14	Structures and Improvements			3782846			1635069
15	Equipment Costs			51266059			63299942
16	Asset Retirement Costs			0			0
17	Total Cost			56551893			64935011
18	Cost per KW of Installed Capacity (line 17/5) Including			219.0236			551.2310
19	Production Expenses: Oper, Supv, & Engr			361126			12150
20	Fuel			6426769			926506
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			0			0
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			1110090			1511
26	Misc Steam (or Nuclear) Power Expenses			0			0
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			16747			12006
30	Maintenance of Structures			48110			0
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			2243355			38140
33	Maintenance of Misc Steam (or Nuclear) Plant			0			0
34	Total Production Expenses			10206197			990313
35	Expenses per Net KWh			0.0848			0.1086
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil		Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf	Bbl		Mcf	Bbl	
38	Quantity (Units) of Fuel Burned	1479348	2258	0	79853	699	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1100897	138937	0	1100897	138937	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.285	98.380	0.000	12.819	98.380	0.000
41	Average Cost of Fuel per Unit Burned	4.285	118.600	0.000	12.819	118.600	0.000
42	Average Cost of Fuel Burned per Million BTU	3.892	20.324	0.000	11.644	20.324	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.053	0.252	0.000	0.117	0.227	0.000
44	Average BTU per KWh Net Generation	13654.649	12412.520	0.000	10042.025	11168.527	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *ENCOGEN* (d)			Plant Name: *FREDERICKSON 1* (e)			Plant Name: *GOLDENDALE* (f)			Line No.
Combined Cycle			Combined Cycle			Combined Cycle			1
Outdoor			Outdoor			Outdoor			2
1993			2002			2004			3
1993			2002			2004			4
176.40			137.00			315.00			5
161			136			312			6
1676			2812			4520			7
0			0			0			8
165			136			315			9
0			0			0			10
16			0			17			11
200095000			353716408			1115147000			12
1051000			699814			1288140			13
9478994			6178023			36755210			14
153776571			60536471			281663335			15
0			443797			0			16
164306565			67858105			319706685			17
931.4431			495.3146			1014.9419			18
210003			1352651			285632			19
6275798			8019108			28692245			20
0			0			0			21
41609			0			1166958			22
0			0			0			23
0			0			0			24
2326524			739358			2727798			25
0			42824			0			26
0			0			0			27
0			0			0			28
49346			397939			65795			29
81524			240952			111897			30
403964			465171			516774			31
1847586			1253353			1373941			32
69632			69232			469504			33
11305986			12580588			35410544			34
0.0565			0.0356			0.0318			35
Gas	Oil		Gas			Gas			36
Mcf	Bbl		Mcf			Mcf			37
1639961	0	0	2252608	0	0	7177054	0	0	38
1100897	140066	0	1100897	0	0	1100897	0	0	39
3.891	0.000	0.000	3.560	0.000	0.000	3.998	0.000	0.000	40
3.891	0.000	0.000	3.560	0.000	0.000	3.998	0.000	0.000	41
3.534	0.000	0.000	3.234	0.000	0.000	3.631	0.000	0.000	42
0.032	0.000	0.000	0.023	0.000	0.000	0.026	0.000	0.000	43
9022854.000	0.000	0.000	7010.953	0.000	0.000	7085.341	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *FERNDALE* (d)			Plant Name: *WHITEHORN* (e)			Plant Name: *FREDERICKSON* (f)			Line No.
Combined Cycle			Gas Turbine			Gas Turbine			1
Outdoor			Outdoor			Outdoor			2
1994			1981			1981			3
1994			1981			1981			4
280.00			169.20			177.80			5
282			141			140			6
4646			2119			2317			7
0			0			0			8
253			149			149			9
0			0			0			10
0			6			6			11
660396000			28555700			29871760			12
0			364590			785528			13
6594636			1486817			3068750			14
119582292			37596620			37538957			15
1030922			0			0			16
127207850			39448027			41393235			17
454.3138			233.1444			232.8078			18
726128			68986			15346			19
19740108			3453644			3408327			20
0			0			0			21
843880			0			0			22
0			0			0			23
0			0			0			24
2522300			530864			712143			25
0			0			0			26
0			0			0			27
0			0			0			28
0			65795			32898			29
41029			38984			74722			30
775565			0			0			31
1888601			883217			822711			32
406080			0			0			33
26943691			5041490			5066147			34
0.0408			0.1765			0.1696			35
Gas	Oli		Gas	Oil		Gas	Oil		36
Mcf	Bbl		Mcf	Bbl		Mcf	Bbl		37
5085025	3984	0	752335	476	0	797520	756	0	38
1100897	140020	0	1100897	139096	0	1100897	139441	0	39
3.793	101.402	0.000	4.774	104.059	0.000	4.426	108.815	0.000	40
3.793	136.416	0.000	4.774	92.083	0.000	4.426	96.756	0.000	41
3.445	23.197	0.000	4.336	15.762	0.000	4.020	16.521	0.000	42
0.029	0.196	0.000	0.127	0.249	0.000	0.119	0.237	0.000	43
8512.637	8442.377	0.000	29184.305	15790.219	0.000	29699.215	14316.830	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *WILD HORSE* (d)	Plant Name: *HOPKINS RIDGE* (e)	Plant Name: *LOWER SNAKE RIVER* (f)	Line No.
Wind Turbine	Wind Turbine	Wind Turbine	1
Outdoor	Outdoor	Outdoor	2
2006	2005	2012	3
2009	2008	2012	4
273.00	157.00	343.00	5
273	157	343	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
7	6	5	11
638688501	410912792	882776646	12
8131854	0	203682	13
15120072	3413472	31393617	14
408369384	167897695	654812975	15
22037384	12455466	17350201	16
453658694	183766633	703760475	17
1661.7535	1170.4881	2051.7798	18
337742	275728	291907	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
671169	659753	1034985	25
0	0	0	26
2662876	879838	3373052	27
0	0	0	28
60046	61768	30713	29
79077	46701	25483	30
0	0	0	31
6163199	4955171	8380332	32
0	0	0	33
9974109	6878959	13136472	34
0.0156	0.0167	0.0149	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: 5 Column: b

Jointly owned. Amount represents 50% of rated capacity of 754,000 KW.

Schedule Page: 402 Line No.: 5 Column: c

Jointly owned. Amount represents 25% of rated capacity of 1,734,000 KW.

Schedule Page: 403 Line No.: 5 Column: e

Jointly owned. Amount represents PSE's 49.85% share.

Schedule Page: 402 Line No.: 11 Column: b

Colstrip is operated by Talen Montana, LLC. There are no PSE employees at the plant.

Schedule Page: 402 Line No.: 11 Column: c

Colstrip is operated by Talen Montana, LLC. There are no PSE employees at the plant.

Schedule Page: 403 Line No.: 11 Column: e

Facility is operated by Atlantic Power Corporation. There are no PSE employees.

Schedule Page: 403.1 Line No.: -1 Column: e

Peak load plant.

Schedule Page: 403.1 Line No.: -1 Column: f

Peak load plant.

Schedule Page: 402.1 Line No.: 1 Column: c

This is a cogeneration plant.

Schedule Page: 403.1 Line No.: 11 Column: d

Ferndale is operated by NAES Corporation for Puget Sound Energy.

Schedule Page: 402.2 Line No.: -1 Column: b

Peak load plant.

Schedule Page: 402.2 Line No.: -1 Column: c

Peak load plant.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2150 Plant Name: LOWER BAKER (b)	FERC Licensed Project No. 2150 Plant Name: UPPER BAKER (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1925	1959
4	Year Last Unit was Installed	2013	1959
5	Total installed cap (Gen name plate Rating in MW)	115.00	104.80
6	Net Peak Demand on Plant-Megawatts (60 minutes)	105	107
7	Plant Hours Connect to Load	8,760	5,173
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	118	110
10	(b) Under the Most Adverse Oper Conditions	83	90
11	Average Number of Employees	17	17
12	Net Generation, Exclusive of Plant Use - Kwh	385,262	333,791
13	Cost of Plant		
14	Land and Land Rights	4,510,244	2,001,428
15	Structures and Improvements	35,903,750	15,886,615
16	Reservoirs, Dams, and Waterways	121,238,697	122,012,798
17	Equipment Costs	67,422,034	18,752,174
18	Roads, Railroads, and Bridges	1,588,316	2,648,182
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	230,663,041	161,301,197
21	Cost per KW of Installed Capacity (line 20 / 5)	2,005.7656	1,539.1336
22	Production Expenses		
23	Operation Supervision and Engineering	820,754	1,106,530
24	Water for Power	0	0
25	Hydraulic Expenses	1,443,696	1,834,367
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	413,539	848,431
28	Rents	0	0
29	Maintenance Supervision and Engineering	119,037	100,041
30	Maintenance of Structures	80,535	63,426
31	Maintenance of Reservoirs, Dams, and Waterways	77,327	151,501
32	Maintenance of Electric Plant	60,962	126,353
33	Maintenance of Misc Hydraulic Plant	2,024,819	1,624,748
34	Total Production Expenses (total 23 thru 33)	5,040,669	5,855,397
35	Expenses per net KWh	13.0837	17.5421

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2493 Plant Name: SNOQUALMIE FALLS (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1898			3
2013			4
54.40	0.00	0.00	5
40	0	0	6
8,754	0	0	7
			8
50	0	0	9
50	0	0	10
18	0	0	11
195,487	0	0	12
			13
554,504	0	0	14
114,462,004	0	0	15
115,733,203	0	0	16
106,048,626	0	0	17
808,565	0	0	18
0	0	0	19
337,606,902	0	0	20
6,206.0092	0.0000	0.0000	21
			22
256,601	0	0	23
0	0	0	24
324,957	0	0	25
234,879	0	0	26
1,328,980	0	0	27
0	0	0	28
109,524	0	0	29
184,273	0	0	30
291,566	0	0	31
1,112,827	0	0	32
403,570	0	0	33
4,247,177	0	0	34
21.7261	0.0000	0.0000	35

Schedule Page: 406 Line No.: 11 Column: b

There were a total of 39 permanent employees at Baker. They work at both Upper Baker and Lower Baker so split the total number between the two.

Schedule Page: 406 Line No.: 11 Column: c

There were a total of 39 permanent employees at Baker. They work at both Upper Baker and Lower Baker so split the total number between the two.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			29
			30
			31
			32
			33
			34
			35
			36
			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	INTERNAL COMBUSTION					
2	Crystal Mountain	1969	2.75	2.7	70,890	2,812,124
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
1,022,591	75,186	10,508	106,138	Diesel	1,714	2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

Schedule Page: 410 Line No.: 2 Column: e

Generation is in kWh.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	3rd Ac Trans Line		500.00	500.00				
2	Broadview S Y	Townsend A Line	500.00	500.00	SCST	133.40		1
3	Broadview S Y	Townsend B Line	500.00	500.00	SCST	133.40		1
4	Colstrip 3	Switch Yard	500.00	500.00	SCST	0.40		1
5	Colstrip 4	Switch Yard	500.00	500.00	SCST	0.40		1
6	Colstrip SY	Broadview A Line	500.00	500.00	SCST	112.70		1
7	Colstrip SY	Broadview B Line	500.00	500.00	SCST	115.90		1
8	500 Kv Tot							
9	Bpa Covington	Berrydale	230.00	230.00	DCST,SCST	4.06		2
10	Bpa Covington	White River #2	230.00	230.00	DCST	9.25		1
11	Bpa Custer	Portal Way	230.00	230.00	WHF	0.06		1
12	Bpa Maple Valley	Talbot #1	230.00	230.00	SCST	0.18		1
13	Bpa Maple Valley	Talbot #2	230.00	230.00	SCST	0.15		1
14	Bpa Monroe	Novelty Hill	230.00	230.00	SCST, DCST	0.27		1
15	Bpa Olympia	Saint Clair	230.00	230.00	DCST	3.62		1
16	Bpa Shelton	South Bremerton	230.00	230.00	WHF	0.80		1
17	Cascade	White River	230.00	230.00	SCST, WHF	68.99		1
18	Christopher	O'Brien #4	230.00	230.00	DCST	4.75		1
19	Colstrip 1	Switch Yard	230.00	230.00	SCST	0.40		1
20	Colstrip 2	Switch Yard	230.00	230.00	SCST	0.40		1
21	Dodge Junction	Phalen Gulch	230.00	230.00	WHF	5.22		1
22	Freddy/APC	Bpa South Tacoma #1	230.00	230.00	UG CABLE	0.97		1
23	Horse Ranch Tap	Bpa Monroe Snohomish	230.00	230.00	WHF, SCST	3.48		1
24	North Intertie		230.00	230.00				
25	Phalen Gulch	BPA Central Ferry	230.00	230.00	WHF	2.08		1
26	Poison Spring	Wind Ridge	230.00	230.00	HF2	4.10		1
27	Rocky Reach	Cascade	230.00	230.00	WHF, SCST	57.86		1
28	Saint Clair	Bpa South Tacoma	230.00	230.00	DCST	3.62		1
29	Sammamish	Bpa Maple Valley #1	230.00	230.00	DCST, SCST	8.14		1
30	Sammamish	Novelty Hill #2	230.00	230.00	DCST, SCST	7.91		1
31	SCL Bothell	Sammamish	230.00	230.00	WHF	13.28		1
32	Sedro Woolley	Bpa Bellingham	230.00	230.00	WHF	0.11		1
33	Sedro Woolley	Horse Ranch	230.00	230.00	SCST	38.95		1
34	Sedro Woolley	March Point	230.00	230.00	SWP, DCST	23.07		1
35	Sedro Woolley	SCL Bothell	230.00	230.00	WHF	49.04		1
36					TOTAL	2,610.54		40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	Sedro Woolley Tap		230.00	230.00	WHF	0.17		1
2	Talbot	Berrydale #3	230.00	230.00	DCST	15.78		2
3	Talbot	O'Brien #3	230.00	230.00	DCST	7.22		1
4	Wanapum	Wind Ridge	230.00	230.00	RHES-MOD,P	21.11		1
5	Wild Horse	Poison Spring	230.00	230.00	HF2	4.52		1
6	White River	Alderton #5	230.00	230.00	SCST, DCST	8.34		1
7	230 KV Tot							
8	115 KV Tot					1,668.97		
9	55 KV Tot					77.47		
10	ARC as per FAS 143							
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	2,610.54		40

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
4-795 ACSR								2
4-795 ACSR								3
2-2250 ACSR								4
2-2250 ACSR								5
4-795 ACSR								6
4-795 ACSR								7
	1,753,427	115,815,658	117,569,085					8
2-1590 ACSS								9
2-1272 ACSR								10
795 ACSR								11
2-1780 ACSR								12
2-1780 ACSR								13
1780 ACSR								14
1590 ACSS								15
1590 ACSR								16
1272 ACSR								17
2-1272 ACSR								18
1272 ACSR								19
1272 ACSR								20
2-1272 ACSR								21
1750 KCML								22
1272 ACSR								23
								24
1272 ACSR								25
1272 ACSR								26
2-1590 ACSR								27
1590 ACSS								28
1780 ACSR								29
1780 ACSR								30
1590 ACSS								31
1.6" AACTW								32
2-795 ACSR								33
2-397.5 ACSR								34
2-795 ACSR								35
	44,878,594	800,685,537	845,564,131	14,088,233	9,978,394	372,875	24,439,502	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1590 ACSR								1
2-1590 ACSR								2
2-1272 ACSR								3
2-1272 ACSR								4
1272 ACSR								5
1590 ACSS								6
	13,778,501	221,827,758	235,606,259					7
	29,080,243	438,657,507	467,737,750					8
	266,423	19,913,094	20,179,517					9
		4,471,520	4,471,520					10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
				14,088,233	9,978,394	372,875	24,439,502	33
								34
								35
	44,878,594	800,685,537	845,564,131	14,088,233	9,978,394	372,875	24,439,502	36

Schedule Page: 422 Line No.: 1 Column: a

Facilities are solely owned by the Bonneville Power Administration. Respondent has secured a life-of facilities capacity ownership interest and will be responsible for its share of plant costs and expenses.

Schedule Page: 422 Line No.: 2 Column: a

Facilities are jointly owned with Pennsylvania Power and Light, Avista, Portland General Electric, and Pacificorp. Plant costs and expenses reflect the respondent's share.

Schedule Page: 422 Line No.: 3 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 4 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 5 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 6 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 7 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 22 Column: a

Facilities are jointly owned with APC (Atlantic Power Corporation). Plant cost and expenses reflect the respondent's share.

Schedule Page: 422 Line No.: 24 Column: a

Facilities are solely owned by the Bonneville Power Administration. Respondent has secured a life-of facilities capacity ownership interest and will be responsible for its share of plant costs and expenses.

Schedule Page: 422.1 Line No.: 7 Column: a

Type of support structure is SP-W, WHF, Steel Tower, and single Wood.

Schedule Page: 422.1 Line No.: 9 Column: a

Asset retirement cost per FAS 143 was added in 2005.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Alderton	Krain Corner	3.51	HPA, HPD, HTSR	10.00	35	35
2	White River	Alderton #1	3.51	HPA,HPD,VDE	10.50	37	37
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		7.02		20.50	72	72

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1272 ACSR			115	3,434,847	3,740,806			7,175,653	1
1272 ACSR			115						2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				3,434,847	3,740,806			7,175,653	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ALDERTON PIERCE	TU	230.00	115.00	13.20
2	BERRYDALE SOUTH KING	TU	230.00	115.00	13.20
3	BPA BELLINGHAM	TU	230.00	115.00	13.20
4	CASCADE KITTITAS	TU	230.00	115.00	34.50
5	CASCADE KITTITAS	TU	230.00	34.50	
6	DODGE JUNCTION GARFIELD	TU	230.00	34.50	
7	FREDONIA SKAGIT	TU	230.00	13.20	
8	GOLDENDALE GOLDENDALE	TU	230.00	18.00	13.80
9	MARCH POINT SKAGIT	TU	230.00	115.00	13.20
10	NOVELTY HILL NORTH KING	TU	230.00	115.00	13.20
11	O'BRIEN SOUTH KING	TU	230.00	115.00	13.20
12	MINT FARM LONGVIEW	TU	230.00	18.00	
13	MINT FARM LONGVIEW	TU	230.00	13.80	
14	PHALEN GULCH GARFIELD	TU	230.00	34.50	
15	PORTAL WAY WHATCOM	TU	230.00	115.00	13.20
16	SAMMAMISH NORTH KING	TU	230.00	115.00	13.20
17	SEDRO WOOLLEY SKAGIT	TU	230.00	115.00	13.20
18	SOUTH BREMERTON SOUTH PENNISULA	TU	230.00	115.00	13.20
19	ST CLAIR THURSTON	TU	230.00	115.00	13.20
20	TALBOT HILL CENTRAL KING	TU	230.00	115.00	13.20
21	TONO THURSTON	TU	525.00	115.00	13.20
22	WHITE RIVER TRANSM. EAST PIERCE	TU	230.00	115.00	13.20
23	WILD HORSE WIND FARM STATION KITTITAS	TU	230.00	34.50	
24	WIND RIDGE KITTITAS	TU	230.00	115.00	13.20
25	TOTAL TRANSMISSION STATIONS		5815.00	2041.00	246.30
26					
27	AIRPORT THURSTON	DU	115.00	12.50	
28	ALGER SKAGIT	DU	115.00	12.50	
29	ALPAC SOUTH KING	DU	115.00	12.50	
30	ANACORTES SKAGIT	DU	115.00	12.50	
31	ARCO NORTH FERNDALE	DU	115.00	12.50	
32	ARCO SOUTH FERNDALE	DU	115.00	12.50	
33	ARCO CENTRAL FERNDALE	DU	115.00	12.50	
34	ARDMORE REDMOND	DU	115.00	12.50	
35	ASBURY SOUTH KING	DU	115.00	12.50	
36	AVONDALE REDMOND	DU	115.00	12.50	
37	BAKER RIVER LOWER SKAGIT	DU	115.00	13.80	
38	BAKER RIVER SW. SKAGIT	DU	115.00	34.50	
39	BAKER RIVER SW. SKAGIT	DU	34.50	12.50	
40	BAKER RIVER UPPER SKAGIT	DU	115.00	13.80	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BAKER RIVER UPPER SKAGIT	DU	12.50	2.40	
2	BAKERVIEW WHATCOM	DU	115.00	12.50	
3	BARNES LAKE THURSTON	DU	115.00	12.50	
4	BELLIS WHATCOM	DU	115.00	12.50	
5	BELMORE SOUTH WEST KING	DU	115.00	12.50	
6	BERTHUSEN WHATCOM	DU	115.00	12.50	
7	BIG ROCK SKAGIT	DU	115.00	12.50	
8	BIRCH BAY WHATCOM	DU	115.00	12.50	
9	BLACKBURN	DU	115.00	12.50	
10	BLACK DIAMOND SOUTH EAST KING	DU	115.00	12.50	
11	BLAINE WHATCOM	DU	115.00	12.50	
12	BLUMAER THURSTON	DU	115.00	12.50	
13	BONNEY LAKE EAST PIERCE	DU	115.00	12.50	
14	BOW LAKE SOUTH WEST KING	DU	115.00	12.50	
15	BREMERTON SOUTH PENNISULA	DU	115.00	12.50	
16	BRIDLE TRAILS CENTRAL KING	DU	115.00	12.50	
17	BRIGHTWATER IPS NORTH KING	DU	115.00	4.00	
18	BRITTON WHATCOM	DU	115.00	12.50	
19	BROOKS HILL ISLAND	DU	115.00	12.50	
20	BUCKLEY EAST PIERCE	DU	55.00	12.50	
21	BUCKLIN HILL NORTH PENNISULA	DU	115.00	12.50	
22	BURLINGTON SKAGIT	DU	115.00	12.50	
23	BURROWS BAY SKAGIT	DU	115.00	12.50	
24	CAMBRIDGE SOUTH KING	DU	115.00	12.50	
25	CAPITOL THURSTON	DU	115.00	12.50	
26	CAROLINA WHATCOM	DU	115.00	12.50	
27	CEDARHURST EAST PIERCE	DU	115.00	12.50	
28	CENTER CENTRAL KING	DU	115.00	13.09	
29	CENTER CENTRAL KING	DU	115.00	13.09	
30	CENTRAL KITSAP NORTH PENNISULA	DU	115.00	12.50	
31	CHAMBERS THURSTON	DU	115.00	12.50	
32	CHICO SOUTH PENNISULA	DU	115.00	12.50	
33	CHICO SOUTH PENNISULA	DU	34.50	12.50	
34	CHRISTENSENS CORNER NORTH PENNISULA	DU	115.00	12.50	
35	CHRISTOPHER AUBURN	DU	115.00	12.50	
36	CLAY CREEK SOUTH EAST KING	DU	55.00	7.00	
37	CLE ELUM KITTITAS	DU	115.00	34.50	
38	CLOVER VALLEY ISLAND	DU	115.00	12.50	
39	CLYDE HILL CENTRAL KING	DU	115.00	12.50	
40	CLYMER KITTITAS	DU	115.00	12.50	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	COLLEGE CENTRAL KING	DU	115.00	12.50	
2	COTTAGE BROOK NORTH KING	DU	115.00	12.50	
3	COUPEVILLE ISLAND	DU	115.00	12.50	
4	CRESCENT HARBOR ISLAND	DU	115.00	13.00	
5	CRESTWOOD NORTH KING	DU	115.00	12.50	
6	CRYSTAL MOUNTAIN GEN. SE KING	DU	34.50	12.50	
7	CRYSTAL MOUNTAIN GEN. SE KING	DU	12.50	4.16	
8	CUMBERLAND SE KING	DU	115.00	12.50	
9	CUSTER WHATCOM	DU	115.00	12.50	
10	DECATUR THURSTON	DU	115.00	12.50	
11	DES MOINES SOUTH WEST KING	DU	115.00	12.50	
12	DIERINGER EAST PIERCE	DU	115.00	12.50	
13	DUPONT EAST PIERCE	DU	115.00	12.50	
14	DUVALL NORTH KING	DU	115.00	12.50	
15	EARLINGTON SOUTH KING	DU	115.00	12.50	
16	EAST PORT ORCHARD SOUTH PENNISULA	DU	115.00	12.50	
17	EAST VALLEY SOUTH KING	DU	115.00	12.50	
18	EASTGATE CENTRAL KING	DU	115.00	12.50	
19	EASTON KITTITAS	DU	115.00	12.50	
20	EDGEWOOD EAST PIERCE	DU	115.00	12.50	
21	ELD INLET THURSTON	DU	115.00	12.50	
22	ELECTRON GEN. EAST PIERCE	DU	115.00	2.40	
23	ELECTRON HEIGHTS EAST PIERCE	DU	55.00	12.50	
24	ELECTRON HEIGHTS EAST PIERCE	DU	115.00	55.00	
25	ELECTRON HEIGHTS EAST PIERCE	DU	55.00	2.40	
26	ELLINGSON SOUTH EAST KING	DU	115.00	12.50	
27	ENCOGEN GEN. WHATCOM	DU	115.00	13.80	
28	ENCOGEN GEN. WHATCOM	DU	115.00	13.80	
29	ENUMCLAW SOUTH EAST KING	DU	115.00	12.50	
30	EVERGREEN NORTH KING	DU	115.00	12.50	
31	FABER ISLAND	DU	115.00	12.50	
32	FACTORIA CENTER KING	DU	115.00	12.50	
33	FAIRCHILD EAST PIERCE	DU	115.00	12.50	
34	FAIRWOOD CENTRAL KING	DU	115.00	12.50	
35	FALCON SOUTH KING	DU	115.00	12.50	
36	FALL CITY EAST KING	DU	115.00	12.50	
37	FERNWOOD SOUTH PENNISULA	DU	115.00	12.50	
38	FOSS CORNER	DU	115.00		
39	FOUR CORNERS SOUTH EAST KING	DU	115.00	12.50	
40	FRAGARIA SOUTH PENNISULA	DU	115.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	FREDERICKSON GEN STATION E PIERCE	DU	115.00	13.20	
2	FREDERICKSON GEN STATION E PIERCE	DU	12.50	4.20	
3	FREDERICKSON GEN STATION E PIERCE	DU	12.50		
4	FREDERICKSON GEN STATION E PIERCE	DU	115.00	6.60	
5	FREDONIA SKAGIT	DU	115.00	13.20	
6	FREDONIA SKAGIT	DU	115.00	12.50	13.20
7	FREELAND ISLAND	DU	115.00	12.50	
8	FREEWAY SOUTH WEST KING	DU	115.00	12.50	
9	FRIENDLY GROVE THURSTON	DU	115.00	13.09	
10	FRUITLAND EAST PIERCE	DU	115.00	12.50	
11	GAGES SKAGIT	DU	115.00	12.50	
12	GARDELLA EAST PIERCE	DU	115.00	12.50	
13	GLACIER WHATCOM	DU	55.00	12.50	
14	GLENCARIN SOUTH KING	DU	115.00	12.50	
15	GOODES CORNER EAST KING	DU	115.00	12.50	
16	GRADY SOUTH KING	DU	115.00	12.50	
17	GRAVELLY LAKE EAST PIERCE	DU	115.00	12.50	
18	GREENBANK ISLAND	DU	115.00	12.50	
19	GREENWATER SOUTH EAST KING	DU	55.00	13.90	
20	GREENWATER SOUTH EAST KING	DU	34.50	12.50	
21	GRIFFIN THURSTON	DU	115.00	12.50	
22	HAMILTON SKAGIT	DU	115.00	12.50	
23	HANNEGAN WHATCOM	DU	115.00	12.50	
24	HAPPY VALLEY WHATCOM	DU	115.00	12.50	
25	HARVEST SOUTH KING	DU	115.00	12.50	
26	HAWKS PRAIRIE THURSTON	DU	115.00	13.09	
27	HAZELWOOD CENTRAL KING	DU	115.00	12.50	
28	HEMLOCK EAST PIERCE	DU	115.00	12.50	
29	HICKOX SKAGIT	DU	115.00	12.50	
30	HIGHLANDS CENTRAL KING	DU	115.00	12.50	
31	HILLCREST ISLAND	DU	115.00	12.50	
32	HOBART SOUTH EAST KING	DU	115.00	12.50	
33	HOLDEN EAST PIERCE	DU	115.00	12.50	
34	HOLLYWOOD NORTH KING	DU	115.00	12.50	
35	HOPKINS RIDGE WIND FARM Columbia Cnty	DU	115.00	34.50	
36	HOUGHTON NORTH KING	DU	115.00	12.50	
37	HYAK EAST KING	DU	115.00	12.50	
38	INGLEWOOD NORTH KING	DU	115.00	12.50	
39	JOHNSON HILL THURSTON	DU	115.00	12.50	
40	JUANITA NORTH KING	DU	115.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	KAPOWSIN EAST PIERCE	DU	115.00	12.50	
2	KENDALL WHATCOM	DU	115.00	12.50	55.00
3	KENILWORTH NORTH KING	DU	115.00	12.50	
4	KENMORE NORTH KING	DU	115.00	12.50	
5	KENT SOUTH KING	DU	115.00	12.50	
6	KINGSTON	DU	115.00	12.50	
7	KITTITAS	DU	115.00	12.50	
8	KITTS CORNER SOUTHWEST KING	DU	115.00	12.50	
9	KLAHANIE EAST KING	DU	230.00	12.50	
10	KNOBLE EAST PIERCE	DU	115.00	12.50	
11	KRAIN CORNER SOUTH EAST KING	DU	115.00	55.00	
12	LABOUNTY WHATCOM	DU	115.00	12.50	
13	LACEY THURSTON	DU	115.00	12.50	
14	LAKE HILLS CENTRAL KING	DU	115.00	12.50	
15	LAKE LEOTA NORTH KING	DU	115.00	12.50	
16	LAKE LOUISE WHATCOM	DU	115.00	12.50	
17	LAKE MCDONALD EAST KING	DU	115.00	12.50	
18	LAKE MERIDIAN SOUTH KING	DU	115.00	12.50	
19	LAKE TAPPS EAST PIERCE	DU	55.00	12.50	
20	LAKE WILDERNESS SOUTH KING	DU	115.00	12.50	
21	LAKE YOUNGS SOUTH KING	DU	115.00	12.50	
22	LAKOTA SOUTHWEST KING	DU	115.00	12.50	
23	LANGLEY ISLAND	DU	115.00	12.50	
24	LAUREL WHATCOM	DU	115.00	13.09	
25	LEA HILL SOUTHEAST KING	DU	115.00	12.50	
26	LIQUID AIR (Airgas) SOUTH KING -	DU	115.00	4.20	
27	LOCHLEVEN CENTRAL KING	DU	115.00	13.09	
28	LONG LAKE SOUTH PENNISULA	DU	115.00	12.50	
29	LONGMIRE THURSTON	DU	115.00	12.50	
30	LUHR BEACH THURSTON	DU	115.00	12.50	
31	LYNDEN WHATCOM	DU	115.00	12.50	
32	M STREET SOUTH EAST KING	DU	115.00	12.50	
33	MANCHESTER SOUTH PENNISULA	DU	115.00	12.50	
34	MANHATTAN SOUTHWEST KING	DU	115.00	12.50	
35	MAPLEWOOD CENTRAL KING	DU	115.00	12.50	
36	MARCH POINT COGEN SKAGIT	DU	115.00	13.80	
37	MARINE VIEW SOUTHWEST KING	DU	115.00	12.50	
38	MAXWELTON ISLAND COUNTY	DU	115.00	13.00	
39	MCALLISTER SPRINGS THURSTON	DU	115.00	12.50	
40	MCKENZIE WHATCOM	DU	115.00	12.50	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MCKINLEY THURSTON	DU	115.00	12.50	
2	MCWILLIAMS NORTH PENNISULA	DU	115.00	12.50	
3	MEDINA CENTRAL KING	DU	115.00	12.50	
4	MERCER ISLAND CENTRAL KING	DU	115.00	12.50	
5	MERCERWOOD CENTRAL KING	DU	115.00	12.50	
6	MERIDETH SOUTH EAST KING	DU	115.00	12.50	
7	MIDLAKES CENTRAL KING	DU	115.00	12.50	
8	MIDWAY SOUTH WEST KING	DU	115.00	12.50	
9	MILLER BAY NORTH PENNISULA	DU	115.00	12.50	
10	MIRRORMONT EAST KING	DU	115.00	12.50	
11	MOBILE UNIT #2 SOUTH KING	DU	66.00	12.50	
12	MOBILE UNIT #3 SOUTH KING	DU	115.00	12.50	
13	MOBILE UNIT #4 SOUTH KING	DU	115.00	12.50	
14	MOBILE UNIT #5 SOUTH KING	DU	115.00	12.50	
15	MOBILE UNIT #6 SOUTH KING	DU	115.00	12.50	
16	MOTTMAN THURSTON	DU	115.00	12.50	
17	MOUNT SI NORTH KING	DU	115.00	12.50	
18	MOUNT VERNON SKAGIT	DU	115.00	12.50	
19	MURDEN COVE NORTH PENNISULA	DU	115.00	12.50	
20	NORKIRK NORTH KING	DU	115.00	12.50	
21	NORLUM SKAGIT	DU	115.00	12.50	
22	NORPAC SOUTHKING	DU	115.00	12.50	
23	NORTH BELLEVUE CENTRAL KING	DU	115.00	13.09	
24	NORTH BEND EAST KING	DU	115.00	12.50	
25	NORTH BOTHELL NORTHKING	DU	115.00	12.50	
26	NORTH NORMANDY SOUTHWEST KING	DU	115.00	12.50	
27	NORTHRUP CENTRAL KING	DU	115.00	12.50	
28	NORWAY HILL NORTH KING	DU	115.00	12.50	
29	NUGENTS CORNER WHATCOM	DU	34.50	12.50	
30	NUGENTS CORNER WHATCOM	DU	115.00	34.50	
31	NUGENTS CORNER WHATCOM	DU	12.50	12.50	
32	OLD TOWN WHATCOM	DU	115.00	12.50	
33	OLYMPIA BREWERY THURSTON	DU	115.00	12.50	
34	OLYMPIC ARCO PUMP WHATCOM	DU	115.00	4.20	
35	OLYMPIC AVON SKAGIT	DU	115.00	4.20	
36	OLYMPIC MOBIL WHATCOM	DU	115.00	4.20	
37	OLYMPIC RENTON SOUTH KING	DU	115.00	4.20	
38	OLYMPIA SWITCH	DU	115.00		
39	OLYMPIC VAIL PIPELINE THURSTON	DU	115.00	4.20	
40	OLYMPIC BAYVIEW SKAGIT	DU	115.00	4.36	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ORCHARD SOUTH KING	DU	115.00	12.50	
2	ORILLIA SOUTH KING	DU	115.00	12.50	
3	ORTING EAST PIERCE	DU	115.00	12.50	
4	OSCEOLA SOUTH EAST KING	DU	115.00	12.50	
5	OVERLAKE CENTRAL KING	DU	115.00	12.50	
6	PACCAR CENTRAL KING	DU	115.00	12.50	
7	PADILLA BAY PIPELINE SKAGIT	DU	115.00	12.50	
8	PADILLA BAY PIPELINE SKAGIT	DU	12.50	4.16	
9	PANTHER LAKE SOUTH KING	DU	115.00	12.50	
10	PATTERSON THURSTON	DU	115.00	12.50	
11	PEASLEY CANYON SOUTHWEST KING	DU	115.00	12.50	
12	PETHS CORNER SKAGIT	DU	115.00	12.50	
13	PHANTOM LAKE CENTRAL KING	DU	115.00	12.50	
14	PICKERING CENTRAL KING	DU	115.00	12.50	
15	PINE LAKE EAST KING	DU	115.00	12.50	
16	PIPE LAKE SOUTH EAST KING	DU	115.00	12.50	
17	PLATEAU EAST KING	DU	115.00	12.50	
18	PLEASANT GLADE THURSTON	DU	115.00	12.50	
19	PLUM STREET THURSTON	DU	115.00	13.09	
20	PLYMOUTH WHATCOM	DU	115.00	12.50	
21	POINT ROBERTS WHATCOM	DU	25.00	12.50	
22	PORT GAMBLE NORTH PENNISULA	DU	115.00	12.50	
23	PORT MADISON NORTH PENNISULA	DU	115.00	12.50	
24	POULSBO NORTH PENNISULA	DU	115.00	12.50	
25	PRESIDENT PARK CENTRAL KING	DU	115.00	13.09	
26	PRINE THURSTON	DU	115.00	13.09	
27	PRINE THURSTON	DU	115.00	12.50	
28	QUARRY EAST PIERCE	DU	115.00	12.50	
29	RAINIER VIEW THURSTON	DU	115.00	12.50	
30	REDMOND NORTH KING	DU	115.00	12.50	
31	REDONDO SOUTHWEST KING	DU	115.00	12.50	
32	RENTON JUNCTION SOUTH KING	DU	115.00	12.50	
33	RHODES LAKE EAST PIERCE	DU	115.00	12.50	
34	RITA STREET SKAGIT	DU	115.00	12.50	
35	RIVERBEND SKAGIT	DU	115.00	12.50	
36	ROCHESTER THURSTON	DU	115.00	12.50	
37	ROCKY POINT SOUTH PENNISULA	DU	115.00	12.50	
38	ROEDER WHATCOM	DU	115.00	13.09	
39	ROLLING HILLS SOUTH KING	DU	115.00	12.50	
40	ROSE HILL CENTRAL KING	DU	115.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SAHALEE NORTH KING	DU	115.00	12.50	
2	SAINT CLAIR THURSTON	DU			
3	SAMMAMISH NORTH KING	DU	115.00	12.50	
4	SCENIC NORTH KING	DU	115.00	12.50	
5	SCHUETT WHATCOM	DU	115.00	12.50	
6	SEATAC SOUTH KING	DU	115.00	13.09	
7	SEHOME WHATCOM	DU	115.00	12.50	
8	SEMIAHMOO WHATCOM	DU	115.00	12.50	
9	SEQUOIA SOUTH KING	DU	115.00	12.50	
10	SERWOLD NORTH PENNISULA	DU	115.00	12.50	
11	SHANNON WHATCOM	DU	34.50	12.50	
12	SHANNON WHATCOM	DU	115.00	34.50	
13	SHAW EAST PIERCE	DU	115.00	12.50	
14	SHERIDAN NORTH PENNISULA	DU	115.00	12.50	
15	SHERWOOD SOUTH EAST KING	DU	115.00	12.50	
16	SHUFFLETON YARD SOUTH KING	DU	55.00	12.50	
17	SHUFFLETON YARD SOUTH KING	DU	55.00	7.20	
18	SHUFFLETON YARD SOUTH KING	DU	12.50	12.50	
19	SHUFFLETON YARD SOUTH KING	DU	12.50	4.20	
20	SHUFFLETON YARD SOUTH KING	DU	34.50	12.50	
21	SHUFFLETON YARD SOUTH KING	DU	115.00	34.50	
22	SHUFFLETON YARD SOUTH KING	DU	115.00	12.50	
23	SHUFFLETON YARD SOUTH KING	DU	115.00	12.50	
24	SHUFFLETON YARD SOUTH KING	DU	230.00	115.00	34.50
25	SILVERDALE NORTH PENNISULA	DU	115.00	12.50	
26	SINCLAIR INLET SOUTH PENNISULA	DU	115.00	12.50	
27	SKYKOMISH NORTH KING	DU	115.00	12.50	
28	SLATER WHATCOM	DU	115.00	12.50	
29	SNOQUALMIE EAST KING	DU	115.00	12.50	
30	SNOQUALMIE (BLACK CREEK GEN)	DU	34.50	12.50	
31	SNOQUALMIE GEN. #1	DU	117.90	6.90	2.00
32	SNOQUALMIE GEN. #2	DU	117.90	7.20	
33	SOMERSET CENTRAL KING	DU	115.00	12.50	
34	SOOS CREEK SOUTH KING	DU	115.00	12.50	
35	SOUTH BELLEVUE CENTRAL KING	DU	115.00	12.50	
36	SOUTH KEYPORT NORTH PENNISULA	DU	115.00	12.50	
37	SOUTH KIRKLAND NORTH KING	DU	115.00	12.50	
38	SOUTH MERCER CENTRAL KING	DU	115.00	12.50	
39	SOUTHWICK THURSTON	DU	115.00	12.50	
40	SOUTHCENTER SOUTH KING	DU	115.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SOUTH WHIDBEY SWITCH ISLAND	DU	115.00		
2	SPANAWAY EAST PIERCE	DU	115.00	12.50	
3	SPIRITBROOK NORTH KING	DU	115.00	12.50	
4	SPURGEON CREEK	DU	115.00	12.50	
5	STARWOOD SOUTH KING	DU	115.00	12.50	
6	STATE STREET WHATCOM	DU	115.00	13.09	
7	STERLING NORTH KING	DU	115.00	12.50	
8	STEWART EAST PIERCE	DU	115.00	12.50	
9	SUMAS GEN STATION	DU	115.00	13.80	
10	SUMMIT PARK SKAGIT	DU	115.00	12.50	
11	SUMNER EAST PIERCE	DU	115.00	12.50	
12	SUNRISE EAST PIERCE	DU	115.00	12.50	
13	SWANTOWN ISLAND	DU	115.00	12.50	
14	SWEPTWING SOUTHWEST KING	DU	115.00	12.50	
15	TANGLEWILDE THURSTON	DU	115.00	12.50	
16	TEN MILE WHATCOM	DU	115.00	4.20	
17	TEXACO EAST SKAGIT	DU	115.00	13.80	
18	TEXACO WEST SKAGIT	DU	115.00	13.80	
19	THORP KITTITAS	DU	34.50	12.50	
20	THURSTON THURSTON	DU	115.00	12.50	
21	TILLICUM EAST PIERCE	DU	115.00	12.50	
22	TOLT NORTH KNG	DU	115.00	12.50	
23	TOTEM NORTH KING	DU	115.00	12.50	
24	TRACYTON NORTH PENNISULA	DU	115.00	12.50	
25	UNION HILL EAST KING	DU	115.00	13.09	
26	VALLEY JUNCTION	DU	115.00		
27	VAN WYCK WHATCOM	DU	115.00	12.50	
28	VASHON SOUTH PENNISULA	DU	115.00	12.50	
29	VICTORIA PARK SOUTH KING	DU	115.00	12.50	
30	VIKING WHATCOM	DU	115.00	12.50	
31	VISTA WHATCOM	DU	115.00	12.50	
32	VITULLI NORTH KING	DU	115.00	12.50	
33	WABASH SOUTH EAST KING	DU	55.00	12.50	
34	WAYNE NORTH KING	DU	115.00	12.50	
35	WEST AUBURN SOUTHWEST KING	DU	115.00	12.50	
36	WEST CAMPUS SOUTHWEST KING	DU	115.00	12.50	
37	WEST ISSAQUAH EAST KING	DU	115.00	13.09	
38	WEST OLYMPIA THURSTON	DU	115.00	12.50	
39	WHIDBEY ISLAND OAK HARBOR	DU			
40	WEYERHAEUSER SW KING	DU	115.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	WEYERHAEUSER WHR BRANCH	DU	55.00	4.16	
2	WHITEHORN WHATCOM	DU	115.00	13.20	
3	WHITE RIVER TRANSM. EAST PIERCE	DU	115.00	55.00	
4	WHITE RIVER TRANSM. EAST PIERCE	DU	55.00	7.20	
5	WHITEHORN GEN WHATCOM	DU	12.50		
6	WHITEHORN GEN WHATCOM	DU	12.50	0.50	
7	WHITEHORN GEN WHATCOM	DU	12.50	4.20	
8	WILKESON EAST PIERCE	DU	55.00	12.50	
9	WILSON SKAGIT	DU	115.00	12.50	
10	WINSLOW NORTH PENNISULA	DU	115.00	12.50	
11	WOBURN WHATCOM	DU	115.00	12.50	
12	WOLDALE KITTITAS	DU	115.00	12.50	
13	WOODLAND EAST PIERCE	DU	115.00	12.50	
14	YELM THURSTON	DU	115.00	12.50	
15	ZENITH SOUTHWEST KING	DU	115.00	12.50	
16	TOTAL DISTRIBUTION STATIONS		37369.80	4448.39	104.70
17					
18	SUMMARY - TRANSMISSION CAPACITY		5815.00	2041.00	246.30
19	SUMMARY - DISTRIBUTION CAPACITY		37369.80	4448.39	104.70
20	TOTAL		43184.80	6489.39	351.00
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
325	1		Static Capacitor	1	21	1
325	1		Static Capacitor	1	42	2
325	1					3
50	1					4
50	1					5
200	1		Reactor	1	10	6
210	2					7
365	1					8
325	1		Static Capacitor	1	23	9
325	1		Static Capacitor	1	42	10
650	2	1	Static Capacitor	1	42	11
215	1					12
160	1					13
200	1		Reactor	1	10	14
325	1					15
650	2		Static Capacitor	2	84	16
650	2		Static Capacitor	2	42	17
325	1					18
325	1		Static Capacitor	1	42	19
650	2		Static Capacitor	1	42	20
533	3	1				21
650	2		Static Capacitor	1	45	22
390	3		Static Capacitor	8	106	23
325	1		Reactor	1	45	24
8548	34	2		23	596	25
						26
20	1		Static Capacitor	1	4	27
9	1					28
50	2		Static Capacitor	2	6	29
20	1		Static Capacitor	1	5	30
80	2		Static Capacitor	1	24	31
80	2		Static Capacitor	1	24	32
80	2					33
50	2		Static Capacitor	2	10	34
25	1		Static Capacitor	1	5	35
25	1		Static Capacitor	1	5	36
133	2					37
25	1					38
8	1					39
120	3	1				40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
3	3					1
25	1		Static Capacitor	1	5	2
20	1		Static Capacitor	1	5	3
25	1		Static Capacitor	1	5	4
50	2		Static Capacitor	2	9	5
25	1		Static Capacitor	1	5	6
20	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	2	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	2	10
25	1		Static Capacitor	1	5	11
20	1		Static Capacitor	1	2	12
25	1		Static Capacitor	1	5	13
75	3		Static Capacitor	1	5	14
50	2		Static Capacitor	2	10	15
50	2		Static Capacitor	2	11	16
13	1					17
20	1		Static Capacitor	1	5	18
20	1					19
19	2		Static Capacitor	1	2	20
25	1					21
25	1		Static Capacitor	1	5	22
25	1					23
25	1		Static Capacitor	1	5	24
50	2					25
20	1		Static Capacitor	1	5	26
25	1		Static Capacitor	1	5	27
40	1		Static Capacitor	1	6	28
25	1		Static Capacitor	1	6	29
25	1		Static Capacitor	1	2	30
25	1		Static Capacitor	1	10	31
25	1		Static Capacitor	1	5	32
16	2					33
20	1		Static Capacitor	1	5	34
25	1		Static Capacitor	1	5	35
1	1	1				36
50	1					37
20	1		Static Capacitor	1	5	38
25	1		Static Capacitor	1	5	39
12	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1		Static Capacitor	1	5	1
25	1		Static Capacitor	1	5	2
20	1					3
25	1		Static Capacitor	1	5	4
25	1		Static Capacitor	1	5	5
8	1		Static Capacitor			6
4	1					7
25	1		Static Capacitor	1	3	8
20	1		Static Capacitor	1	5	9
20	1		Static Capacitor	1	2	10
25	1		Static Capacitor	1	5	11
25	1					12
20	1		Static Capacitor	1	5	13
25	1					14
25	1		Static Capacitor	2	6	15
25	1		Static Capacitor	1	5	16
25	1		Static Capacitor	1	5	17
50	2		Static Capacitor	1	5	18
20	1					19
25	1		Static Capacitor	1	2	20
20	1		Static Capacitor	1	2	21
25	1					22
2	1					23
40	3					24
3	2					25
25	1		Static Capacitor	1	4	26
150	3					27
68	1					28
25	1		Static Capacitor	1	2	29
50	2		Static Capacitor	2	10	30
25	1		Static Capacitor	1	4	31
50	2		Static Capacitor	2	10	32
50	2		Static Capacitor	1	5	33
25	1		Static Capacitor	1	3	34
25	1		Static Capacitor	1	5	35
20	1					36
25	1		Static Capacitor	1	5	37
			Static Capacitor	1	23	38
25	1		Static Capacitor	1	5	39
25	1		Static Capacitor	1	2	40

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
170	2					1
2	2					2
3	2					3
			Spare GSU			4
110	2					5
75		1	Spare GSU			6
20	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	5	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	5	10
25	1		Static Capacitor	1	5	11
25	1		Static Capacitor	1	5	12
5	1					13
25	1		Static Capacitor	1	5	14
25	1		Static Capacitor	1	5	15
25	1		Static Capacitor	1	5	16
20	1		Static Capacitor	1	5	17
9	1					18
20	1		Static Capacitor	1	5	19
8	1					20
20	1		Static Capacitor	1	5	21
20	1					22
20	1		Static Capacitor	1	2	23
25	1					24
50	2		Static Capacitor	1	5	25
25	1		Static Capacitor	1	2	26
25	1		Static Capacitor	1	3	27
25	1		Static Capacitor	1	5	28
25	1					29
25	1		Static Capacitor	1	5	30
20	1		Static Capacitor	1	3	31
25	1		Static Capacitor	1	2	32
20	1		Static Capacitor	1	2	33
25	1		Static Capacitor	1	5	34
167	2		Static Capacitor	2	29	35
25	1		Static Capacitor	1	5	36
20	1		Static Capacitor	1	5	37
25	1		Static Capacitor	1	5	38
25	1		Static Capacitor	1	5	39
50	2		Static Capacitor	2	10	40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1		Static Capacitor	1	5	1
30	1	1	Static Capacitor	1	2	2
25	1		Static Capacitor	1	5	3
25	1		Static Capacitor	1	5	4
50	2		Static Capacitor	2	8	5
25	1		Static Capacitor	1	5	6
25	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	5	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	5	10
40	1					11
20	1		Static Capacitor	1	5	12
25	1		Static Capacitor	1	4	13
25	1		Static Capacitor	1	5	14
25	1		Static Capacitor	1	5	15
20	1		Static Capacitor	1	5	16
25	1		Static Capacitor	1	5	17
25	1					18
18	1		Static Capacitor	1	2	19
25	1		Static Capacitor	1	5	20
25	1		Static Capacitor	1	5	21
25	1		Static Capacitor	1	5	22
20	1					23
25	1		Static Capacitor	1	5	24
25	1		Static Capacitor	1	3	25
20	2					26
50	2		Static Capacitor	2	12	27
25	1		Static Capacitor	2	10	28
25	1		Static Capacitor	1	5	29
25	1		Static Capacitor	1	2	30
40	2		Static Capacitor	2	10	31
25	1		Static Capacitor	1	5	32
25	1		Static Capacitor	1	2	33
25	1		Static Capacitor	1	5	34
25	1		Static Capacitor	1	5	35
140	3					36
25	1		Static Capacitor	1	5	37
25	1		Static Capacitor	1	5	38
25	1					39
20	1		Static Capacitor	1	5	40

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
25	1		Static Capacitor	1	5	1
20	1		Static Capacitor	1	2	2
25	1					3
25	1					4
20	1					5
25	1		Static Capacitor	1	5	6
25	1		Static Capacitor	1	5	7
			Static Capacitor	1	42	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	5	10
9	1					11
25	1					12
15	1					13
25	1					14
25	1					15
20	1		Static Capacitor	1	5	16
25	1	1	Static Capacitor	1	2	17
25	1		Static Capacitor	1	2	18
25	1		Static Capacitor	1	5	19
25	1		Static Capacitor	1	5	20
20	1					21
25	1		Static Capacitor	1	5	22
50	2		Static Capacitor	2	10	23
25	1		Static Capacitor	1	5	24
25	1		Static Capacitor	1	5	25
20	1		Static Capacitor	1	5	26
25	1		Static Capacitor	1	5	27
25	1		Static Capacitor	1	5	28
8	1					29
25	1					30
5	1					31
20	1		Static Capacitor	1	5	32
20	1		Static Capacitor	1	5	33
6	1					34
19	2					35
9	1					36
9	1					37
			Static Capacitor	1	42	38
6	1					39
6	1					40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1		Static Capacitor	1	4	1
25	1		Static Capacitor	1	5	2
25	1		Static Capacitor	1	2	3
20	1		Static Capacitor	1	2	4
25	1					5
50	2		Static Capacitor	2	10	6
9	1					7
4	1					8
25	1		Static Capacitor	1	5	9
20	1		Static Capacitor	1	5	10
25	1		Static Capacitor	1	5	11
20	1		Static Capacitor	1	2	12
25	1		Static Capacitor	1	5	13
25	1		Static Capacitor	1	5	14
25	1		Static Capacitor	1	5	15
25	1		Static Capacitor	1	3	16
25	1		Static Capacitor	1	5	17
25	1		Static Capacitor	1	5	18
25	1		Static Capacitor	1	5	19
25	1					20
19	2					21
20	1		Static Capacitor	1	4	22
25	1		Static Capacitor	1	5	23
25	1					24
25	1		Static Capacitor	1	5	25
25	1		Static Capacitor	1	5	26
20	1		Static Capacitor	1	5	27
9	1					28
25	1		Static Capacitor	1	5	29
50	2		Static Capacitor	2	10	30
25	1		Static Capacitor	1	5	31
50	2		Static Capacitor	2	10	32
25	1		Static Capacitor	1	5	33
20	1					34
20	1		Static Capacitor	1	5	35
40	2		Static Capacitor	1	5	36
50	2					37
20	1		Static Capacitor	1	5	38
25	1		Static Capacitor	1	5	39
25	1		Static Capacitor	1	5	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
25	1		Static Capacitor	1	5	1
			Static Capacitor	1	40	2
25	1	1	Static Capacitor	1	5	3
4	1					4
20	1					5
50	2					6
25	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	5	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	5	10
8	1					11
25	1			1	5	12
25	1		Static Capacitor	1	5	13
40	1		Static Capacitor	1	5	14
25	1		Static Capacitor	1	5	15
9		1				16
3		1				17
5		1				18
8		1				19
9		1				20
25		1				21
25		11				22
13		1				23
50		1				24
25	1		Static Capacitor	1	5	25
20	1		Static Capacitor	1	5	26
9	1					27
20	1		Static Capacitor	1	5	28
25	1					29
5	1					30
20	1					31
53	1					32
25	1		Static Capacitor	1	5	33
25	1		Static Capacitor	1	5	34
25	1		Static Capacitor	1	5	35
20	1		Static Capacitor	1	4	36
25	1		Static Capacitor	1	5	37
20	1					38
25	1		Static Capacitor	1	5	39
25	1		Static Capacitor	1	5	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
			Static Capacitor	2	42	1
20	1		Static Capacitor	1	5	2
25	1		Static Capacitor	1	5	3
25	1		Static Capacitor	1	5	4
50	2		Static Capacitor	2	10	5
25	1		Static Capacitor	1	5	6
50	2		Static Capacitor	2	10	7
25	1		Static Capacitor	1	5	8
240	2					9
20	1		Static Capacitor	1	4	10
20	1		Static Capacitor	1	5	11
25	1		Static Capacitor	1	5	12
20	1					13
25	1		Static Capacitor	1	3	14
20	1		Static Capacitor	1	5	15
9	1					16
50	2					17
80	2					18
9	1					19
50	2		Static Capacitor	1	5	20
20	1		Static Capacitor	1	5	21
25	1					22
25	1		Static Capacitor	1	5	23
20	1		Static Capacitor	1	2	24
25	1		Static Capacitor	1	5	25
			Static Capacitor	1	23	26
9	1					27
50	2		Static Capacitor	2	10	28
25	1		Static Capacitor	1	5	29
20	1		Static Capacitor	1	5	30
20	1		Static Capacitor	1	5	31
50	2		Static Capacitor	2	10	32
9	1					33
25	1					34
25	1		Static Capacitor	1	4	35
25	1		Static Capacitor	1	2	36
25	1		Static Capacitor	1	5	37
20	1		Static Capacitor	1	5	38
			Static Capacitor	1	23	39
20	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
8	3					1
170	2					2
83	3					3
3	3					4
1	2					5
2	2					6
2	2					7
9	1					8
25	1		Static Capacitor	1	5	9
25	1					10
25	1					11
20	1					12
25	1		Static Capacitor	1	2	13
25	1		Static Capacitor	2	26	14
25	1		Static Capacitor	1	5	15
9729	398	25		258	1,453	16
						17
8548	34	2		23	596	18
9729	398	25		258	1,453	19
18277	432	27		281	2,049	20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426 Line No.: 24 Column: i

The act of installing Shunt Reactor is to meet the requirements of Grant County as a condition to connect or intertie onto the transmission system located at Wild Horse. This equipment serves to reduce the wind farm's turbine impact when producing energy during times of low load conditions in the surrounding area. This translates in allowing PSE to produce all the power it can from the wind turbine generation system during these light load conditions but it does not (as a component) add capacity.

Schedule Page: 426 Line No.: 29 Column: a

Safeway Distribution Center leases PSE owned transformer at Alpac (Algona-Pacific / Boeing-Auburn #2) Substation. Service started November 2004.

Schedule Page: 426 Line No.: 31 Column: a

BP West Coast Products leases PSE owned transformer at ARCO North Substation under schedule 449.

Schedule Page: 426 Line No.: 32 Column: a

BP West Cost Products leases PSE owned transformer at ARCO South Substation under schedule 449.

Schedule Page: 426 Line No.: 33 Column: a

BP West Coast Products leases PSE owned transformer at ARCO Central Substation under schedule 449.

Schedule Page: 426.1 Line No.: 17 Column: a

Waste Water Treatment Division - Brightwater leases PSE owned transformer at Brightwater Substation. Expiration 5/21/2020.

Schedule Page: 426.1 Line No.: 25 Column: a

State of Washington Admin leases PSE owned transformer at Capitol Substation. Service started November 1972.

Schedule Page: 426.1 Line No.: 38 Column: a

Navy Ault leases PSE owned transformer at Clover Valley Substation. Service started November 1972.

Schedule Page: 426.2 Line No.: 13 Column: a

Center Drive Owners Association leases transformer at Dupont Substation. Service began 12/1/2018.

Schedule Page: 426.2 Line No.: 33 Column: a

Benaroya leases PSE owned transformer at Fairchild Substation. Service started December 2005.

Schedule Page: 426.4 Line No.: 26 Column: a

Air Liquide Industrial US LP leases PSE owned transformer at Liquid Air Substation.

Schedule Page: 426.5 Line No.: 10 Column: a

BioEnergy leases PSE owned transformer at Mirrormont Substation.

Schedule Page: 426.5 Line No.: 25 Column: a

AT&T leases PSE owned transformer at North Bothell Substation.

Schedule Page: 426.5 Line No.: 34 Column: a

Praxair and Olympic Pipeline lease PSE owned transformers at Olympic Arco Pump Substation. Services started July 1979.

Schedule Page: 426.5 Line No.: 35 Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Avon Substation. Service started April 2004.

Schedule Page: 426.5 Line No.: 36 Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Mobil Substation. Service started April 2004.

Schedule Page: 426.5 Line No.: 37 Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Renton Substation. Service started April 2004.

Schedule Page: 426.5 Line No.: 39 Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Vail Substation. Service started April 2004.

Schedule Page: 426.5 Line No.: 40 Column: a

Olympic Pipeline leases PSE owned transformer at Olympic Bayview Substation.

Schedule Page: 426.6 Line No.: 6 Column: a

PACCAR Inc. leases PSE owned transformer at PACCAR Substation. Service started December 1992.

Schedule Page: 426.6 Line No.: 7 Column: a

Olympic Pipeline leases PSE owned transformer at Padilla Bay Substation.

Schedule Page: 426.6 Line No.: 38 Column: a

Bellingham Cold Storage leases PSE owned transformer at Roeder Substation. Service started May 1967.

Schedule Page: 426.7 Line No.: 3 Column: a

AT&T leases PSE owned transformer at Sammamish Substation. Service started 2010.

Schedule Page: 426.8 Line No.: 7 Column: a

Microsoft leases PSE owned transformer at Sterling Substation. Service started 2010.

Schedule Page: 426.8 Line No.: 16 Column: a

Trans Mountain Pipeline leases PSE owned transformer at Ten Mile Substation. The substation was energized 10/17/08.

Schedule Page: 426.8 Line No.: 17 Column: a

Shell leases PSE owned transformer at Texaco East Substation under Schedule 449.

Schedule Page: 426.8 Line No.: 18 Column: a

Shell leases PSE owned transformer at Texaco West Substation under Schedule 449.

Schedule Page: 426.8 Line No.: 30 Column: a

Western Washington University leases PSE owned transformer at Viking Substation.

Schedule Page: 426.8 Line No.: 32 Column: a

AT&T Wireless and The Seattle Times lease PSE owned transformers at Vitulli Substation. Services started December 2006 and August 1991.

Schedule Page: 426.8 Line No.: 40 Column: a

Federal Way Campus leases PSE owned transformer at Weyerhaeuser Substation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule | Page No.