THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

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) Puget Sound Energy, Inc.	Year/Period of Report End of: 2023/ 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, Licensees, and Others 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 Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

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.)

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 [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF 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. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

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 https://www.ferc.gov/general-information-0/electric-industry-forms.

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, 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.

X. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

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 by 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 shall 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 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: 2023/ 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 Stacy Smith		06 Title of Contact Person Controller and Principal Accounting Officer
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 (425) 454-6363	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/16/2024
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 Stacy Smith 02 Title Controller and Principal Accounting Officer	03 Signature Stacy Smith	04 Date Signed (Mo, Da, Yr) 04/16/2024
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: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
47	**Purchased Power**	326	
48	**Transmission of Electricity for Others**	328	
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 (Account 403, 404, 405)**	336	
53	**Regulatory Commission Expenses**	350	
54	**Research, Development and Demonstration Activities**	352	N/A
55	**Distribution of Salaries and Wages**	354	
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**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	
64	**Hydroelectric Generating Plant Statistics**	406	
65	**Pumped Storage Generating Plant Statistics**	408	N/A
66	**Generating Plant Statistics Pages**	410	
66.1	**Energy Storage Operations (Large Plants)**	414	N/A
66.2	**Energy Storage Operations (Small Plants)**	419	
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☑ No annual report to stockholders is prepared		
Page 2			

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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.

Stacy Smith, Controller and Principal Accounting Officer

P.O. BOX 97034 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.

State of Incorporation: WA

Date of Incorporation: 1960-09-12

Incorporated Under Special Law:

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.

N/A

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

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 WashingtonNatural 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

(2)
☑ No

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent 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 beneficiaries 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: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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%	

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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)	Date Started in Period (d)	Date Ended in Period (e)
1	President and Chief Executive Officer	Mary E. Kipp	1,072,507		
2	[(a)] Chief Financial Officer (Contract)	Daniel A. Doyle		2023-09-26	
3	Senior Vice President and Chief Customer and Transformation Officer	Aaron August	177,727	2023-07-27	
4	Senior Vice President, General Counsel and Chief Sustainability Officer	Lorna Luebbe	493,371		
5	Senior Vice President, Energy Resources	Ron Roberts	436,838		
6	Vice President and Chief Human Resources Officer	Kim Collier	390,488		
7	Vice President, Clean Energy Strategy and Planning	Josh Jacobs	375,874		
8	Vice President, Development	Craig Pospisil	138,659	2023-08-21	
9	Senior Vice President, Energy Operations	Michelle Vargo	129,261	2023-07-24	
10	Senior Vice President, External Affairs	Matthew Steuerwalt	93,500	2023-09-29	
11	Vice President, Regulatory Affairs	Jon Piliaris	284,111	2023-05-11	
12	Former Vice President, Finance	Josh Kensok	293,025	2023-08-03	2024-03-08
13	[(b)] Chief Information Officer (Contract)	Simon Upton		2023-03-13	
14	Director, Controller and Principal Accounting Officer	Stacy Smith	244,955		
15	Director, Corporate Treasurer	Cara Peterman	276,575		
16	Former Executive Vice President and Chief Financial Officer	Kazi Hasan	459,123		2023-09-26
17	Former Executive Vice President and Chief Operating Officer	Allen (Wade) Smith	647,548		2023-12-15
18	Former Vice President, Energy Delivery	Daniel Koch	319,487		2023-12-29
19	Former Senior Vice President Shared Services & Chief Information Officer	Margaret F. Hopkins	163,357		2023-05-01
20	Former Senior Vice President and Chief Customer Officer	Andrew Wappler	121,644		2023-04-03
21	Former Vice President, External Affairs	Ken Johnson	115,748		2023-05-05

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FOOTNOTE DATA

(a) Concept: OfficerTitle

No salary was paid as the associated officer was not a full-time employee during 2023, but rather hired on a contract basis.

(b) Concept: OfficerTitle

No salary was paid as the associated officer was not a full-time employee during 2023, but rather hired on a contract basis.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Scott Armstrong	Seattle, WA		
2	Richard Dinneny	Victoria, B.C		
3	Barbara Gordon	Bellevue, WA		
4	Chris Parker	Toronto, Ontario		
5	[(a)] Christine Gregoire	Seattle, WA		
6	[(b)] Julia Hamm	Marco Island, FL		
7	Grant Hodgkins	Victoria, B.C.		
8	Thomas King	Houston, Texas		
9	Mary Kipp (President & CEO)	Bellevue, WA		
10	[(c)] Jenine Krause	Toronto, Ontario		
11	Paul McMillan	Calgary, Alberta		
12	Diana Birkett Rakow	Seattle, WA		
13	Aaron Rubin	New York, NY		
14	Steven Zucchet	Toronto, Ontario		
15	[(d)] Jean-Paul Marmoreo	Toronto, Ontario		

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FOOTNOTE DATA

(a) Concept: NameAndTitleOfDirector
Effective February 24, 2023, Christine Gregoire was elected to serve on the Board of Directors of Puget Sound Energy.
(b) Concept: NameAndTitleOfDirector
Effective May 1, 2023, Julia Hamm was elected to serve on the Board of Directors of both Puget Energy and Puget Sound Energy.
(c) Concept: NameAndTitleOfDirector
Effective February 2, 2024, Jenine Krause was elected to serve on the Board of Directors of both Puget Energy and Puget Sound Energy.
(d) Concept: NameAndTitleOfDirector
Effective February 2, 2024, Jean-Paul Marmoreo resigned from serving on the boards of both Puget Energy and Puget Sound Energy.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ 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 (a)	FERC Proceeding (b)
1	FERC Electric Tariff	FERC Docket No. ER12-778-001
2	FERC Electric Tariff Amendment	FERC Docket No. ER18-1249-000 Amendment to OATT Schedules 7, 8, and 10 to revise depreciation rates. Letter order issued May 19, 2018 accepting tariff revisions (Assession No. 201803305155)
3	FERC Electric Tariff Amendment	FERC Docket No. ER20-1958-000 Amendment to OATT creating Worksheet 7 to meet Order No.864 requirements regarding excess deferred federal income tax
4	FERC Electric Tariff Amendment	FERC Docket No. ER23-22-002 Ammendment to OATT Attachment H-2 Formula Rate Implementation Protocols

Name of Respondent:	This report is:	Date of Report:	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☑ An Original (2) ☐ A Resubmission	04/16/2024	End of: 2023/ 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 ☐ No

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

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20180601-5313	06/01/2018	ER12-889-001	[(a)] [(b)] Informational Filing of Annual Update	FERC Electric Tariff
2	20180529-5249	05/16/2018	ER18-1695-000	Petition for limited waiver of tariff provisions.	FERC Electric Tariff
3	20220228-5031	02/28/2022	ER20-1958-002	Order No. 864 Compliance Filing	FERC Electric Tariff
4	20231024-3073	10/05/2022	ER23-22-002	Commision Section 106 proceeding revising PSE OATT Attachment H-1	FERC Electric Tariff

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfFiling
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.

(b) Concept: DescriptionOfFiling
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: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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). (a)	Schedule (b)	Column (c)	Line No. (d)
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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

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 Pages 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.

(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.

Q1:

Location (WA)	County	Type	Category	Initial Term	Consideration
Edgewood	Pierce	Electric and Natural Gas	Extension	5 years	$—
All unincorporated communities	Snohomish	Natural Gas	New	10 years	$—
Pacific	King	Natural Gas	Expired		$—

Q2:

Location (WA)	County	Type	Category	Initial Term	Consideration
All unincorporated communities	Island	Electric	Expired		$—
Jackson Prairie facility	Lewis	Water	Expired		$—
North Bend	King	Electric and Natural Gas	New	25 years	$—
University Place	Pierce	Natural Gas	New	20 years	$—

Q3:

Location (WA)	County	Type	Category	Initial Term	Consideration
Enumclaw	King	Electric	Expired		$—

Q4: None.

2. None.

3. None.

4. None.

5. None.

6.

Credit Facilities

As of December 31, 2023, no amount was drawn under PSE's credit facility and $336.6 million was outstanding under the commercial paper program.

Outside of the credit facility, PSE maintains a standby letter of credit with TD Bank allowing for standby letter of credit postings of up to $150.0 million as a condition of transacting on the ICE NGX platform as well as participating in the Washington state carbon allowance auctions. As of December 31, 2023, $51.0 million was issued under a standby letter of credit in support of natural gas and carbon allowance purchases. Additionally, PSE had a $2.1 million letter of credit in support of a long-term transmission contract.

Long Term Debt

On May 18, 2023, PSE issued $400.0 million of green senior secured notes at an interest rate of 5.448%. The notes mature on June 1, 2053 and pay interest semi-annually in arrears on June 1 and December 1 of each year, commencing December 1, 2023. Net proceeds from the issuance of the notes were deposited into the Company's general account and are

intended to be used for allocation to eligible projects, as defined in PSE's sustainable financing framework, which was published in May 2023. Eligible projects are expenditures incurred and investments made related to development and acquisition of some or all of the following types of projects: (i) renewable energy, (ii) energy efficiency, (iii) clean transportation, (iv) biodiversity conservation, (v) climate change adaptation, (vi) water and wastewater management, (vii) pollution prevention and control, and (viii) green innovation. For further information, see Note 6, "Long-Term Debt" and Note 7, "Liquidity Facilities and Other Financing Arrangements" in the Company's most recent Annual Report on Form 1 for the year ended December 31, 2023.

7. None.

8.

Non-represented employees received on average a 10.50% increase effective on March 1, 2023. Employees of the IBEW received a 3.0% salary increase effective on January 1, 2023. Employees of the UA received a 3.0% salary increase effective on October 1, 2023. The estimated annual effect of these changes is $30.3 million. The current contracts with the IBEW and UA will expire March 31, 2026 and September 30, 2025, respectively.

9. Legal Proceedings:

Regulation and Rates

General Rate Case Filing

PSE filed a GRC which includes a two year multiyear rate plan (MYRP) with the Washington Commission on February 15, 2024, requesting an overall increase in electric and natural gas rates of 6.7% and 19.0% respectively in rate year one (expected to approximate calendar year 2025) and 8.5% and 2.1%, respectively in rate year two (expected to approximate calendar year 2026). PSE requested a return on equity of 9.95% for the first rate year beginning in 2025 and 10.5% for the second rate year beginning in 2026. PSE requested an overall rate of return of 7.65% in rate year one and 7.99% in rate year two. The filing requests recovery of forecasted plant additions through 2024 as required by RCW 80.28.425 as well as forecasted plant additions through 2026, the final year of the MYRP. The next phase of the filing will be to establish a procedural calendar for the adjudication of the case. The Company estimates the agreed upon rates from this proceeding will become effective by statute approximately 11 months after filings.

On December 22, 2022, the Washington Commission issued an order on PSE's 2022 general rate case (GRC), which was filed on January 31, 2022, that approved a weighted cost of capital of 7.16%, or 6.62% after-tax, a capital structure of 49.0% in common equity in 2023 and 2024, and a return on equity of 9.4%. On January 6, 2023, the Washington Commission approved PSE's natural gas rates in its compliance filing with an overall net revenue change of $70.8 million or 6.4% in 2023 and $19.5 million or 1.7% in 2024, with an effective date of January 7, 2023. On January 10, 2023, the Washington Commission approved PSE's electric rates in its compliance filing with an overall net revenue change of $247.0 million or 10.8% in 2023 and $33.1 million or 1.3% in 2024 with an effective date of January 11, 2023. Per the 2022 GRC Final Order in Docket No. UE-220066, rates approved in PSE's power cost only rate case (PCORC) in Docket No. UE-200980 were set to zero as of January 11, 2023, and PSE agreed not to file a PCORC during 2023 and 2024, the period covered by the two-year rate plan agreed to in the GRC settlement.

Prior rates were subject to the 2019 GRC and included a weighted cost of capital of 7.39% or 6.8% after-tax, and a capital structure of 48.5% in common equity with a return on equity of 9.4%. The annualized overall rate impacts were an electric revenue increase of $48.3 million, or 2.3%, and a natural gas increase of $4.9 million, or 0.6%, effective October 1, 2021. For further information, see Note 3, "Regulation and Rates" to the consolidated financial statements included in the Company's Form 1 for the period ended December 31, 2022.

Climate Commitment Act Deferral

On December 29, 2022, PSE filed accounting petitions with the Washington Commission requesting authorization to defer costs and revenues associated with the Company's compliance with the Climate Commitment Act (CCA) codified in law within Revised Code of Washington (RCW) 70A.65. On February 28, 2023, in Order 01 under Docket No. UE-220974 and UG-220975, the Washington Commission granted PSE approval to defer the cost of emission allowances to comply with the CCA and the proceeds from no-cost allowances consigned to auction beginning January 1, 2023. On August 3, 2023, the Washington Commission approved PSE's request for CCA rates in Docket No. UG-230470, subject to refund, effective October 1, 2023, to recover the estimated ongoing allowance costs and proportionate pass back of credits to customers from estimated auction proceeds during the period of August 2023 through December 2023. On October 26, 2023, the Washington

Commission approved PSE's request for CCA rates in Docket No. UG-230756, subject to refund, effective November 1, 2023, to recover the estimated ongoing allowance costs and proportionate pass back of credit to customers from estimated auction proceeds during the period of January 2023 through September 2023. The recovery of ongoing allowance costs and pass back of credits is consistent with the approved accounting petitions in Dockets No. UG-220975 and UG-230471. As of December 31, 2023, PSE deferred $184.4 million of CCA compliance costs for natural gas and electric liabilities. Additionally, PSE will consign for auction at least the minimum amount of no-cost emission allowances allocated for natural gas operations in compliance with the CCA, the proceeds of which will be used for the benefit of natural gas customers, as determined by the Washington Commission. PSE will not record a regulatory liability to defer the proceeds until consigned allowances are sold at auction. As of December 31, 2023, PSE recorded $83.0 million related to the proceeds from the sale of consigned GHG emission allowances.

In October 2022, the Washington Department of Ecology (WDOE) published final regulations to implement the cap and invest program. The WDOE also indicated that it will have subsequent rulemakings building off initial rulemaking as program implementation is underway and progress with Washington State carbon goals are evaluated. One component of the CCA rules stipulates the WDOE shall provide qualifying electric utilities, such as PSE, with no-cost allowances based on the cost burden of the program to electric customers, which is derived using a forecast of emissions. An additional component of the CCA rules stipulates that the allocation of no-cost allowances may be adjusted once a year under a "true-up mechanism" which takes into account the cumulative total of no-cost allowances issued to an electric utility relative to the electric utility's reported GHG emissions. Such adjustments will be made in the fourth quarter of the following year, at which time WDOE could add allowances to an electric utility's account if such account has an allowance deficit, or withhold future allocated allowances going forward if such account had previously allocated excess allowances. WDOE has not provided further guidance or rules specifying how such adjustments will be determined. As a result, the Company cannot predict the impact of such adjustments.

WDOE provided an initial allocation of no-cost allowances to electric utilities on April 24, 2023. However, qualifying electric utilities were allowed to submit revised emissions forecasts approved by the Washington Commission to WDOE by July 30, 2023. PSE filed its revised forecast of 2023 emission under Docket No. UE 220797, which was approved by the Washington Commission on July 27, 2023, and approved by the WDOE on September 27, 2023. Accordingly, the Company's compliance obligation as of December 31, 2023, reflects the revised allowance allocation.

Following the September 27, 2023 WDOE decision, PSE's no-cost allowance allocation will be set for 2023 until the fourth quarter of 2024 when there is an opportunity to request a "true-up" of no-cost allowances under the aforementioned adjustment mechanism. However, as of December 31, 2023, due to the uncertainty around implementation of the adjustment mechanism PSE did not adjust the CCA electric compliance obligation anticipating an adjustment to no cost allowances to reported 2023 electric GHG emissions and does not plan to make such adjustment until a formal true-up allocation has been granted by the WDOE.

Power Cost Adjustment Clause

PSE exceeded the $20.0 million cumulative deferral balance in its PCA mechanism in 2022. During 2022, actual power costs were higher than baseline power costs, thereby, creating an under-recovery of $110.1 million. Under the terms of the PCA's sharing mechanism for under-recovered power costs, PSE absorbed $39.0 million of the under-recovered amount, and customers were responsible for the remaining $71.1 million, or $76.4 million, including interest and adjusted for revenue sensitive items. On April 28, 2023, PSE filed the 2022 PCA report under Docket No. UE-230313 that proposed a recovery of the deferred balance, which included a revenue requirement increase of 0.9% in overall bill for all customers, with rates proposed to go into effect from December 1, 2023 through December 31, 2024.

PSE also exceeded the $20.0 million cumulative deferral balance in its PCA mechanism in 2021, as actual power costs were higher than baseline power costs, thereby creating an under-recovery of $68.0 million. PSE absorbed $31.3 million of the under-recovered amount, and customers were responsible for the remaining $36.7 million, or $38.4 million, including interest. In October 2022, the Washington Commission approved PSE's 2021 PCA report that proposes to recover the deferred balance for 2021 PCA period by keeping the current rates and allowing recovery from January 1, 2023 through November 30, 2023.

On September 29, 2023, PSE filed its variable power cost rates update as part of the 2022 GRC Order requirement under Docket No. UE-220066. The filing was approved in part on December 22, 2023, with updated rates effective January 1, 2024.

Purchased Gas Adjustment Mechanism

In October 2021, the Washington Commission approved PSE's request for PGA rates in Docket No. UG-210721, effective November 1, 2021. As part of that filing, PSE requested an annual revenue increase of $59.1 million, where PGA rates, under Schedule 101, increase annual revenue by $80.6 million, and the tracker rates under Schedule 106, decrease annual revenue by $21.5 million. Those annual 2021 PGA rate increases were set in addition to continuing the collection on

the remaining balance of $69.4 million under Supplemental Schedule 106B, which were set, in effect, through September 30, 2023, per the 2019 GRC.

In October 2022, the Washington Commission approved PSE's request for PGA rates in Docket No. UG-220715, effective November 1, 2022. As part of that filing, PSE requested an annual revenue increase of $155.3 million, where PGA rates, under Schedule 101, increase annual revenue by $142.1 million, and the tracker rates under Schedule 106, increase annual revenue by $13.2 million.

In November 2022, the FERC approved a settlement of a counterparty, FERC Docket No. RP17-346. Under the terms, PSE was allocated $24.2 million related to PSE natural gas services which was recorded on December 31, 2022, and included below. The 2022 GRC order requires PSE to amortize the refund in 2023 as a credit against natural gas costs and therefore pass back the refund to customers through the PGA mechanism.

On October 26, 2023, the Washington Commission approved PSE's request for PGA rates in Docket No. UG-230769, effective November 1, 2023. As part of that filing, PSE requested an annual revenue decrease of $309.4 million, where PGA rates, under Schedule 101, decrease annual revenue by $93.9 million, and the tracker rates under Schedule 106, decrease annual revenue by $215.5 million. The annual 2023 PGA rate decreases include the aforementioned counterparty settlement pass back of $28.1 million under Supplemental Schedule 106B.

Environmental Remediation

The Company is subject to environmental laws and regulations by 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 WDOE and/or other third parties as potentially responsible or liable at several contaminated sites, including former 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. The adjustments recorded are based on the best estimate or the low end of a range of reasonably possible costs expected to be incurred by the Company based on its currently understood legal exposure at applicable sites. It is reasonably possible that incurred costs exceed the recorded amounts due to changes in laws and/or regulations, higher than expected costs due to changes in labor market or supply chain, evolving technology, unforeseen and/or the discovery of new or additional contamination. The Company currently estimates that a significant portion of its past and future environmental remediation costs are recoverable from insurance companies, from third parties, and/or from customers under a Washington Commission order. The Company is subject to cost-sharing agreements with third parties regarding environmental remediation projects in Seattle, Tacoma, Everett, and Bellingham, Washington. As of December 31, 2023, the Company's share of future remediation costs is estimated to be approximately $72.9 million.

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 each of Colstrip Units 3 and 4, which are coal-fired generating units located in Colstrip, Montana. PSE has accelerated the depreciation of Colstrip Units 3 and 4 to December 31, 2025 as part of the 2019 GRC. The 2017 GRC repurposed PTCs and hydro-related treasury grants to recover unrecovered plant costs and to fund and recover decommissioning and remediation costs for Colstrip Units 1 through 4. Additional costs beyond those covered by PTCs and hydro-related treasury grants are being recovered through a separate Colstrip tariff as part of the 2022 GRC. In 2022, PSE and Talen Energy reached an agreement to transfer PSE's ownership interest in Colstrip Units 3 and 4 to Talen Energy on December 31, 2025. Although PSE and Talen Energy signed an agreement in 2022 involving the transfer of PSE's ownership to Talen at the end of 2025, Talen emerged from a Chapter 11 bankruptcy in May 2023 without approval of the agreement, so the parties have agreed to continue discussions about the status of PSE's ownership stake. Management evaluated Colstrip Units 3 and 4 and determined that the applicable held for sale and abandonment accounting criteria were not met as of December 31, 2023. As such, Colstrip Units 3 and 4 are classified as Electric Utility Plant on the Company's balance sheet as of December 31, 2023.

Consistent with a June 2019 announcement, Talen permanently shut down Units 1 and 2 at the end of 2019 due to operational losses associated with the Units. Colstrip Units 1 and 2 were retired effective December 31, 2019. The Washington Clean Energy Transformation Act requires the Washington Commission to provide recovery of the investment, decommissioning, and remediation costs associated with the facilities that are not recovered through the repurposed PTCs
and hydro-related treasury grants. The full scope of decommissioning activities and costs may vary from the estimates that are available at this time.

In May 2021, PSE along with the Colstrip owners, Avista Corporation, PacifiCorp and Portland General Electric Company, filed a lawsuit against the Montana Attorney General challenging the constitutionality of Montana Senate Bill 266. On September 28, 2022, the magistrate judge in the District Court proceeding issued a recommendation to the presiding U.S. District Court Judge that a permanent injunction against enforcement of Senate Bill 266 be granted. In October 2022, the U.S. District Court Judge accepted in full the magistrate judge's recommendation for a permanent injunction against enforcement of Senate Bill 266. The Court entered judgment and a permanent injunction in favor of PSE and the Colstrip owners on November 15, 2022. No party filed a notice of appeal.

Puget LNG

In January 2018, the Puget Sound Clean Air Agency (PSCAA) determined a Supplemental Environmental Impact Statement (SEIS) was necessary in order to rule on the air quality permit for the facility. In December 2019, PSCAA issued the air quality permit for the facility, a decision which was appealed to the Washington Pollution Control Hearings Board (PCHB) by each of the Puyallup Tribe of Indians and nonprofit law firm Earthjustice. In November 2021, the PCHB affirmed the PSCAA ruling in PSE's favor. In December 2021, the PCHB decision was appealed with the Pierce County Superior Court by each of the Puyallup Tribe of Indians and nonprofit law firm Earthjustice. The appeal did not delay commissioning or commercial operations at the plant, which commenced on February 1, 2022. On February 4, 2022, the court transferred the appeal to the Washington Court of Appeals Division II (Wash. Ct. App. Div. II) for direct review. On December 26, 2023 the Wash. Ct. App. Div. II affirmed the PCHB decision on all counts. The State of Washington Division II Court of Appeals upheld the permit issuance and in February 2024 denied the Puyallup Tribe of Indians' motion to reconsider. On March 22, 2024, a coalition of environmental organizations lead by Advocates for a Cleaner Tacoma, petitioned the Washington Supreme Court to review portions of the Court of Appeals' decision. On March 25, 2024, the Puyallup Tribe of Indians also petitioned the Washington Supreme Court for review.

Washington Climate Commitment Act

In 2021, the Washington Legislature adopted the CCA, which establishes a GHG emissions cap-and-invest program that requires covered entities, including electric and natural gas utilities, to purchase allowances to cover their GHG emissions with a cap on available allowances beginning on January 1, 2023 that declines annually through 2050. WDOE published final regulations to implement the program on September 29, 2022, which became effective on October 30, 2022. WDOE also indicated that there will be subsequent rulemakings building off initial rulemaking as program implementation proceeds and Washington carbon goals is evaluated.

One component of the CCA rules stipulates that GHG emissions associated with exported electricity are covered emissions and require an allowance offset to the extent these exports are not sourced from a non-emitting resource. Another component of the CCA rules stipulates GHG emissions associated with imported electricity are covered emissions and require an allowance offset for the first jurisdictional deliverer serving as the electricity importer for that electricity. Per RCW 70A.65.010(42)(d), imported electricity does not include electricity imports of unspecified electricity that are netted by exports of unspecified electricity to any jurisdiction not covered by a linked program by the same entity within the same hour. Under this definition, hourly power transmission data is required to determine PSE's net imported electricity compliance obligation. Although the Company is actively engaged in determining the hourly net generation, imports and exports, the methodology for netting these components by hour that will be required by the WDOE to calculate the compliance obligation is uncertain, and PSE expects further rulemaking and agency interpretations to clarify this uncertainty in future periods. Due to the estimation uncertainty as of the date of this disclosure, the company considered a range of outcomes depending on the proportion of exported electricity that is sourced from non-emitting resources and whether all unspecified electricity imports and exports fully net on an hourly basis, none net, or a portion do. As of December 31, 2023, the Company's estimated the range of possible outcomes to be between $95.9 and $280.2 million depending on the methodology applied in netting unspecified electricity imports and exports. Since no amount in the range represents a better estimate than any other amount, the Company accrued to the minimum amount in the range. As existing uncertainties are resolved in future periods, any change in compliance costs as a result of such estimated additional liabilities would be deferred under ASC 980 as a regulatory asset consistent with Docket No. UE-220974, as these amounts may be recoverable from customers in future utility rates.

Washington Clean Energy Transformation Act

In May 2019, Washington passed the CETA, which supports Washington's clean energy economy and transitioning to a clean, affordable, and reliable energy future. The CETA requires all electric utilities to eliminate coal-fired generation from their electric supply to customers by December 31, 2025; to be carbon-neutral by January 1, 2030 through a combination of non-emitting electric generation, renewable generation, and/or alternative compliance options; and makes it the state policy that, by 2045, 100% of electric generation and retail electricity sales will come from renewable or non-emitting resources. Clean energy implementation plans are required every four years from each investor-owned utility (IOU). The plan must propose interim targets for meeting the 2045 standard between 2030 and 2045 and describe an actionable plan that the IOU intends to pursue to meet the standard. The Washington Commission may approve, reject or recommend alterations to an IOU's plan. The Company intends to seek recovery of any costs associated with CETA through the regulatory process. On December 17, 2021, PSE filed its Final CEIP, which proposed a plan for the implementation of CETA for 2022-2025 and associated project costs. On June 6, 2023, the Washington Commission approved PSE's CEIP, subject to conditions. On November 2, 2023, PSE filed a Biennial CEIP Update with the Commission.

10. Related Party Transactions

Tacoma LNG Facility

In August 2015, PSE filed a proposal with the Washington Commission to develop a liquified natural gas (LNG) facility at the Port of Tacoma. The Tacoma LNG facility provides peak-shaving services to PSE's natural gas customers, and provides LNG as fuel to transportation customers, particularly in the marine market. Following a mediation process and the filing of a settlement stipulation by PSE and all parties, the Washington Commission issued an order on October 31, 2016, that allowed PSE's parent company, Puget Energy, to create a wholly-owned subsidiary, named Puget LNG, which was formed on November 29, 2016, for the sole purpose of owning, developing and financing the non-regulated activity of the Tacoma LNG facility. Puget LNG has entered into one fuel supply agreement with a maritime customer and is marketing the facility's expected output to other potential customers.

On February 1, 2022, the Tacoma LNG facility at the Port of Tacoma completed commissioning and commenced commercial operations. Pursuant to the Washington Commission's order, PSE will be allocated 43.0% of the capital and operating costs of the Tacoma LNG facility. PSE and Puget LNG are considered related parties with similar ownership by Puget Energy. Therefore, capital and operating costs that occur under PSE and are allocated to Puget LNG are related party transactions by nature. Per this allocation of costs, $235.6 million of Natural Gas Plant related to PSE's portion of the Tacoma LNG facility is reported in the utility plant financial statement line item as of December 31, 2023, as PSE is a regulated entity. The portion of the Tacoma LNG facility allocated to PSE will be subject to regulation by the Washington Commission.

11. Reserved.

12. None.

13.

Changes of Ownership:

None.

Changes of Directors or Certain Officers:

a. Effective February 24, 2023, the Boards of Directors (the "Boards") of Puget Energy, Inc. and Puget Sound Energy, Inc. (together, the "Companies") appointed Christine Gregoire as a director of the Companies.
b. On March 8, 2023, Margaret Hopkins notified Puget Sound Energy, Inc. (the "Company") of her intent to retire from her position as Senior Vice President Shared Services and Chief Information Officer of the Company effective as of May 1, 2023.
c. On March 16, 2023, Andrew Wappler notified Puget Sound Energy, Inc. (the "Company") of his intent to retire from his position as Senior Vice President and Chief Customer Officer of the Company effective as of April 3, 2023.
d. On April 21, 2023, the sole shareholder of Puget Energy, Inc. and Puget Sound Energy, Inc. (together, the "Companies") appointed and elected Julia Hamm to the boards of directors of the Companies (the "Boards"), effective May 1, 2023. Martijn Verwoest, who serves as representative of the Companies' affiliated investors on the Boards, resigned from the Boards effective May 1, 2023.

   Ms. Hamm is a member of the board of directors and chair of the compensation committee of Voltera, an electric fleet charging infrastructure company, a role she has held since 2022, and a member of the board of directors of the California Mobility Center, a role she has held since 2021. Ms. Hamm is also the founder and a current board member of Solar Energy Trade Shows, which manages the RE+ energy industry portfolio of trade shows. Ms. Hamm also serves as an advisor to EQT Group, a private equity investment organization, and The Ad Hoc Group, a Climate technology and sustainability-focused consulting firm. Prior to this, Ms. Hamm served as the president and CEO of Smart Electric Power Alliance, a non-profit company, from 2004-2022. Ms. Hamm was selected by an affiliate of PGGM Vermogensbeheer B.V., and pursuant to the Amended and Restated Bylaws of each of the Companies, will serve as an "Owner Director" on their respective boards of directors.

e. On May 5, 2023, Ken Johnson, the Vice President of Regulatory and Government Affairs retired.
f. On May 12 , 2023, Jon Piliaris, the director of Regulatory Affairs for the past five years, was promoted to the vice president of Regulatory Affairs.
g. On July 24, , 2023, Michelle Vargo joined PSE as the Vice President of Shared Services. Michelle is a utility operations executive with experience in operations management, safety culture, change management, continuous improvement, business planning and negotiation. Michelle joined PSE from Seattle City Light, where she most recently served as Chief Operating Officer responsible for all utility transmission, distribution and system operations functions.
h. On July 27, 2023, Aaron August joined PSE as Senior Vice President of Chief Customer and Transformation Officer. Aaron joined PSE from Pacific Gas & Electric (PG&E), where he most recently served as Vice President of Utility Partnerships and Innovation, responsible for non-traditional utility partnerships, research and development, solutions management, load management, clean energy transportation and business development. Prior to that, he was responsible for the strategy, design, implementation, and effectiveness of PG&E's energy programs including energy efficiency, demand response, distributed generation, low income and clean transportation.
i. On August 8, 2023, Josh Kensok was promoted to the Vice President of Finance. On March 8, 2024, Josh Kensok resigned.

j. On August 21, 2023, Craig Pospisil joined PSE as Vice President of Business Development and Mergers & Acquisitions. Prior to PSE, Craig served as vice president, head of Wind Development at Terra Gen from 2017 to August 2023.

k. On September 26, 2023, Kazi Hasan resigned from his position as Executive Vice President and Chief Financial Officer of PSE.

l. PSE appointed Daniel A. Doyle, effective as of September 26, 2023, to serve as interim Chief Financial Officer until a successor is identified. Mr. Doyle previously served as PSE's Senior Vice President and Chief Financial Officer from 2011 to 2021.

m. On September 29, 2023, Matt Steuerwalt joined PSE as Senior Vice President of External Affairs. Matt has worked closely with PSE on policy issues as a partner at Insight Strategic Partners, a Seattle-based public affairs firm specializing in government relations, public policy and strategic communications.

n. On November 17, 2023, Wade Smith notified Puget Sound Energy, Inc. and Puget Energy, Inc. (together, the “Companies”) of his intent to resign from his position as Executive Vice President and Chief Operating Officer of the Companies, effective on or about December 15, 2023.

o. Effective December 29, 2023, Dan Koch, Vice President of Energy Delivery resigned from the Company.

p. Effective January 8, 2024, Ron Roberts was promoted to the Senior Vice President of Energy Resources, and Michelle Vargo was promoted to the Senior Vice President of Energy Operations.

q. On February 2, 2024, the sole shareholder of Puget Energy, Inc. and Puget Sound Energy, Inc. (together, the “Companies”) appointed and elected Jenine Krause to the boards of directors of the Companies (the “Boards”), effective February 2, 2024. Ms. Krause is a Managing Director at OMERS Infrastructure Management Inc. (“OMERS”), since 2022. Previously, she was the Chief Executive Officer of Enercare Inc, a home and commercial service and energy solutions company, from 2018 to 2022, until the company’s sale to Brookfield Infrastructure Partners. Prior to that, Ms. Krause held senior roles at Bell Canada, a telecommunications provider. Ms. Krause is a director of LifeLabs, a Toronto-based laboratory testing service provider, of Beanfield Technologies, a Toronto-based fiber infrastructure network, and of BridgeTex Pipeline Company, a Houston-based pipeline operator. Ms. Krause was selected by OMERS, and pursuant to the Amended and Restated Bylaws of each of the Companies, will serve as an “Owner Director” on their respective boards of directors.

r. Jean-Paul Marmoreo, who serves as representative of the Companies’ affiliated investors on the Boards, resigned from the Boards effective February 2, 2024.

14. None.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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	18,577,648,828	17,795,827,941
3	Construction Work in Progress (107)	200	1,156,264,737	861,801,465
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		19,733,913,565	18,657,629,406
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	7,763,962,154	7,461,206,807
6	Net Utility Plant (Enter Total of line 4 less 5)		11,969,951,411	11,196,422,599
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		11,969,951,411	11,196,422,599
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)		8,783,943	8,783,943
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		3,644,360	3,650,229
19	(Less) Accum. Prov. for Depr. and Amort. (122)		24,656	24,655
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	38,792,842	38,582,474
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		44,639,936	54,983,320
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		20,211,184	20,191,500
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		35,323,976	94,621,186
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		142,587,642	212,004,054
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		37,804,878	88,139,126
36	Special Deposits (132-134)		60,363,961	60,437,596
37	Working Fund (135)		5,664,228	2,607,514
38	Temporary Cash Investments (136)		92,000,000	
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		381,639,286	370,666,115
41	Other Accounts Receivable (143)		179,199,363	326,336,152
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		38,211,010	41,961,715
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		5,199,298	4,043,420
45	Fuel Stock (151)	227	32,347,791	21,182,653
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	173,859,027	131,283,900
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		221,957

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)
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	(167,982,040)	731,067
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	(1,312,553)	156,825
55	Gas Stored Underground - Current (164.1)		49,613,011	66,796,355
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		1,471,548	979,449
57	Prepayments (165)		87,769,352	51,382,582
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		243,342,662	284,014,591
62	Miscellaneous Current and Accrued Assets (174)		3,021,644	3,331,136
63	Derivative Instrument Assets (175)		109,548,647	681,650,782
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		35,323,976	94,621,186
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		1,220,015,117	1,957,378,319
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		23,407,807	24,172,621
70	Extraordinary Property Losses (182.1)	230a	95,753,810	127,524,176
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	799,152,296	565,039,247
73	Prelim. Survey and Investigation Charges (Electric) (183)		779,622	106,872
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)		184,265	137,168
78	Miscellaneous Deferred Debits (186)	233	395,589,865	284,321,034
79	Def. Losses from Disposition of Utility Plt. (187)		3,858,634	5,741,557
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		31,625,503	33,731,648
82	Accumulated Deferred Income Taxes (190)	234	365,019,041	430,016,445
83	Unrecovered Purchased Gas Costs (191)		(132,082,170)	(3,536,308)
84	Total Deferred Debits (lines 69 through 83)		1,583,288,673	1,467,254,460
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		14,924,626,786	14,841,843,375

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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	859,038	859,038
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		478,145,250	478,145,250
7	Other Paid-In Capital (208-211)	253	3,164,096,691	3,064,096,691
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	7,133,879	7,133,879
11	Retained Earnings (215, 215.1, 216)	118	1,486,273,152	1,451,424,351
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(13,054,602)	(13,264,970)
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(58,396,308)	(103,045,030)
16	Total Proprietary Capital (lines 2 through 15)		5,050,789,342	4,871,081,451
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	5,223,860,000	4,823,860,000
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256		
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		18,570,269	15,729,451
24	Total Long-Term Debt (lines 18 through 23)		5,205,289,731	4,808,130,549
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		280,265,535	283,782,671
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		(142,500)	88,000
29	Accumulated Provision for Pensions and Benefits (228.3)		(102,236,489)	(28,709,995)
30	Accumulated Miscellaneous Operating Provisions (228.4)		180,440,185	135,051,835
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities		38,048,777	18,366,683
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		203,037,437	205,559,099
35	Total Other Noncurrent Liabilities (lines 26 through 34)		599,412,945	614,138,293
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		336,600,000	357,000,000
38	Accounts Payable (232)		509,277,531	708,906,799
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		2,051,640	291,713
41	Customer Deposits (235)		7,608,513	13,733,533
42	Taxes Accrued (236)	262	98,255,029	116,472,982
43	Interest Accrued (237)		53,833,663	52,169,671
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		1,380,682	3,951,481
48	Miscellaneous Current and Accrued Liabilities (242)		45,791,718	40,266,693
49	Obligations Under Capital Leases-Current (243)		24,999,694	23,509,170

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)
50	Derivative Instrument Liabilities (244)		223,836,299	143,342,442
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		38,048,777	18,366,683
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,265,585,992	1,441,277,801
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		141,948,045	123,708,753
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)		1,353,225	1,928,264
59	Other Deferred Credits (253)	269	293,574,358	518,347,061
60	Other Regulatory Liabilities (254)	278	920,886,418	891,629,751
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		1,148,658,824	1,177,028,707
64	Accum. Deferred Income Taxes-Other (283)		297,127,906	394,572,745
65	Total Deferred Credits (lines 56 through 64)		2,803,548,776	3,107,215,281
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		14,924,626,786	14,841,843,375

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in 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.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
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 purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders 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.

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)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)
1	UTILITY OPERATING INCOME										
2	Operating Revenues (400)	300	4,994,572,831	4,388,121,714			3,483,981,859	3,178,485,486	1,510,590,972	1,209,636,228	
3	Operating Expenses										
4	Operation Expenses (401)	320	3,113,930,315	2,635,508,553			2,203,863,789	1,970,839,868	910,066,526	664,668,685	
5	Maintenance Expenses (402)	320	182,504,901	175,029,070			152,225,910	147,385,918	30,278,991	27,643,152	
6	Depreciation Expense (403)	336	571,184,422	524,822,928			393,750,409	374,468,383	177,434,013	150,354,545	
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	4,105,749	9,365,324			3,764,421	8,902,654	341,328	462,670	
8	Amort. & Depl. of Utility Plant (404-405)	336	83,766,414	101,835,503			56,875,003	69,876,938	26,891,411	31,958,565	
9	Amort. of Utility Plant Acq. Adj. (406)	336	9,552,226	11,687,828			9,552,226	11,687,828			
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		33,911,798	21,846,432			33,911,798	21,846,432			
11	Amort. of Conversion Expenses (407.2)										
12	Regulatory Debits (407.3)		379,526,844	21,725,532			66,572,207	12,725,650	312,954,637	8,999,882	
13	(Less) Regulatory Credits (407.4)		443,634,375	42,514,738			134,166,092	32,370,162	309,468,283	10,144,576	
14	Taxes Other Than Income Taxes (408.1)	262	407,278,222	386,340,822			269,731,981	259,360,685	137,546,241	126,980,137	
15	Income Taxes - Federal (409.1)	262	217,610,004	81,592,777			179,574,754	41,484,612	38,035,250	40,108,165	
16	Income Taxes - Other (409.1)	262	1,626,265	869,191			1,626,265	869,191			
17	Provision for Deferred Income Taxes (410.1)	234, 272	285,043,374	465,808,227			125,951,781	264,566,257	159,091,593	201,241,970	
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	398,082,515	467,480,717			243,405,410	263,542,456	154,677,105	203,938,261	
19	Investment Tax Credit Adj. - Net (411.4)	266									
20	(Less) Gains from Disp. of Utility Plant (411.6)		611,696	5,013,242			611,696	5,013,242			
21	Losses from Disp. of Utility Plant (411.7)		1,882,923				5,519		1,877,404		
22	(Less) Gains from Disposition of Allowances (411.8)										
23	Losses from Disposition of Allowances (411.9)										
24	Accretion Expense (411.10)		3,205,012	3,834,848			2,969,331	3,539,560	235,681	295,288	
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,452,799,883	3,925,258,338			3,122,192,196	2,886,628,116	1,330,607,687	1,038,630,222	
27	Net Util Oper Inc (Enter Tot line 2 less 25)		541,772,948	462,863,376			361,789,663	291,857,370	179,983,285	171,006,006	
28	Other Income and Deductions										
29	Other Income										

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)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)
30	Nonutilty Operating Income										
31	Revenues From Merchandising, Jobbing and Contract Work (415)		216,099	271,813							
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		404,975	988,707							
33	Revenues From Nonutility Operations (417)		14,166,573	44,808,060							
34	(Less) Expenses of Nonutility Operations (417.1)		19,588,018	40,561,238							
35	Nonoperating Rental Income (418)										
36	Equity in Earnings of Subsidiary Companies (418.1)	119	210,368	270,654							
37	Interest and Dividend Income (419)		2,321,152	(8,731,661)							
38	Allowance for Other Funds Used During Construction (419.1)		39,011,961	28,310,136							
39	Miscellaneous Nonoperating Income (421)		(261,572,131)	289,517,265							
40	Gain on Disposition of Property (421.1)		141,079	235,262							
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		(225,497,892)	313,131,584							
42	Other Income Deductions										
43	Loss on Disposition of Property (421.2)										
44	Miscellaneous Amortization (425)										
45	Donations (426.1)		29,350	36,800							
46	Life Insurance (426.2)		(3,990,191)	(1,759,020)							
47	Penalties (426.3)		688,659	1,529,387							
48	Exp. for Certain Civic, Political & Related Activities (426.4)		8,921,500	8,488,691							
49	Other Deductions (426.5)		34,842,655	40,784,988							
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		40,491,973	49,080,846							
51	Taxes Applic. to Other Income and Deductions										
52	Taxes Other Than Income Taxes (408.2)	262	356,000	681,438							
53	Income Taxes-Federal (409.2)	262	(105,438,142)	(67,633)							
54	Income Taxes-Other (409.2)	262									
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	(7,418,032)	(498,795)							
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272									

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)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)
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)		(112,500,174)	115,010							
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(153,489,691)	263,935,728							
61	Interest Charges										
62	Interest on Long-Term Debt (427)		253,702,267	240,203,334							
63	Amort. of Debt Disc. and Expense (428)		2,648,196	2,651,955							
64	Amortization of Loss on Reaquired Debt (428.1)		2,106,146	2,168,876							
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)		23,454,299	9,268,172							
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		24,686,821	18,443,620							
70	Net Interest Charges (Total of lines 62 thru 69)		257,224,087	235,848,717							
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		131,059,170	490,950,387							
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									
77	Extraordinary Items After Taxes (line 75 less line 76)										
78	Net Income (Total of line 71 and 77)		131,059,170	490,950,387							

Line No.	Other Utility Previous Year to Date (in dollars) (l)
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Line No.	Other Utility Previous Year to Date (in dollars) (l)
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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, 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 for 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 for 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, attach them at page 122.

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		1,415,391,688	961,917,281
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	License Hydro Project Excess Earnings		1,529,011	(1,810,100)
15	TOTAL Debits to Retained Earnings (Acct. 439)		1,529,011	(1,810,100)
16	Balance Transferred from Income (Account 433 less Account 418.1)		130,848,802	490,679,733
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
23.1	Dividends Declared			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Dividends Declared		(96,000,000)	(35,395,226)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(96,000,000)	(35,395,226)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,451,769,501	1,415,391,688
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
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)		34,503,651	36,032,663
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		34,503,651	36,032,663
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,486,273,152	1,451,424,351
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		(13,264,970)	(13,535,624)
50	Equity in Earnings for Year (Credit) (Account 418.1)		210,368	270,654
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)		(13,054,602)	(13,264,970)

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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 Instructions 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)	131,059,170	490,950,387
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	701,164,741	623,814,810
5	Amortization of (Specify) (footnote details)		
5.1	Utility Plant Adjustments	9,552,226	11,687,828
5.2	Property Losses	33,911,798	21,846,432
8	Deferred Income Taxes (Net)	(159,561,273)	(39,619,118)
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	143,622,780	(251,651,225)
11	Net (Increase) Decrease in Inventory	(35,357,685)	(51,304,130)
12	Net (Increase) Decrease in Allowances Inventory	(129,361,113)	
13	Net Increase (Decrease) in Payables and Accrued Expenses	(253,542,012)	227,465,622
14	Net (Increase) Decrease in Other Regulatory Assets	198,975,323	(95,264,559)
15	Net Increase (Decrease) in Other Regulatory Liabilities	157,946,902	71,182,691
16	(Less) Allowance for Other Funds Used During Construction	39,011,961	28,310,136
17	(Less) Undistributed Earnings from Subsidiary Companies	210,368	270,654
18	Other (provide details in footnote):		
18.1	Other Long-Term Assets	(8,896,838)	(5,886,051)
18.2	Other Long-Term Liabilities	(16,080,522)	7,902,780
18.3	Conservation Amortization	121,340,164	116,941,715
18.4	Pension Funding	(18,000,000)	(18,000,000)
18.5	Net Unrealized (Gain) Loss on Derivative Transactions	284,494,614	(261,177,050)
18.6	Prepayments	(36,386,770)	(1,470,474)
18.7	Deferral of Energy Exchange		
18.8	King County Franchise Fee		
18.9	Other	(1,013,184)	(2,070,297)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	1,084,645,992	816,768,571
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,504,936,648)	(1,029,123,626)
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	(39,011,961)	(28,310,136)
31	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,465,924,687)	(1,000,813,490)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	47,800	20,200
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
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):		
53.1	Renewable Energy Credits	(14,981)	(587,046)
53.2	Life Insurance Premiums	14,013,842	
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,451,878,026)	(1,001,380,336)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	395,280,357	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Investment from Parent	100,000,000	50,000,000
66	Net Increase in Short-Term Debt (c)	(20,400,000)	217,000,000
67	Other (provide details in footnote):		
67.1	Costs related to Debt Issuance or Redemption		(8,458)
67.2	Refundable Cash Received for Customer Construction Projects	33,000,508	26,233,489
67.3	Bank Overdraft		
70	Cash Provided by Outside Sources (Total 61 thru 69)	507,880,865	293,225,031
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Proceeds from Long-term Bonds and Notes Issued		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(96,000,000)	(35,395,226)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	411,880,865	257,829,805
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	44,648,831	73,218,040
88	Cash and Cash Equivalents at Beginning of Period	151,184,236	77,966,196
90	Cash and Cash Equivalents at End of Period	195,833,067	151,184,236
	Page 120-121		

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 Commission 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.

(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.

Construction Work in Progress

Construction work in progress represents construction materials, progress payments on major equipment contracts, engineering costs, AFUDC and other costs directly associated with construction projects. Such costs classified as construction work in progress are included within utility plant on the balance sheet. At completion of such projects, these costs are transferred to utility plant in service. Capitalized costs associated with construction activities are charged to operations and maintenance expenses when recoverability is no longer probable.

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 3.4% in 2023 and 2022; depreciable natural gas utility plant was 3.2% and 2.9% in 2023 and 2022, respectively; and depreciable common utility plant was 6.5%, and 7.1% in 2023 and 2022, respectively. The cost of removal is collected from PSE's customers through depreciation expense and any excess is recorded as a regulatory liability.

Related Party Transactions

The Company identified no material related party transactions during the years ended December 31, 2023 and December 31, 2022.

Tacoma LNG Facility

In February 2022, the Tacoma LNG facility at the Port of Tacoma completed commissioning and commenced commercial operations. In December 2019, the Puget Sound Clean Air Agency (PSCAA) issued the air quality permit for the facility, and the Pollution Hearings Control Board of Washington State upheld the approval following extended litigation. The Tacoma LNG facility provides peak-shaving services to PSE's natural gas customers, and provides LNG as fuel to transportation customers, particularly in the marine market at a lower cost due to the facility's scale.

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, $235.6 million and $241.1 million of plant in service related to PSE's portion of the Tacoma LNG facility is reported in the PSE "Utility plant - Natural gas plant" financial statement line item as of December 31, 2023, and December 31, 2022, respectively, 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.

Restricted Cash

Restricted cash amounts primarily represent cash posted as collateral for derivative contracts as well as funds required to be set aside for contractual obligations related to transmission and generation facilities.

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 average cost.

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 3, "Regulation and Rates".

Greenhouse Gas Emission Allowances

PSE is required to obtain emission allowances or offset credits for greenhouse gas (GHG) emissions associated with electricity it generates or imports into Washington and natural gas supplied to customers in accordance with the cap-and-invest program included in the Climate Commitment Act (CCA). PSE records allocated and purchased emission allowances at cost, similar to an inventory method, and includes purchased emissions allowances in current assets and long-term assets reported in the "GHG emission allowances" line item on the consolidated balance sheets. PSE measures the compliance obligation at the weighted average cost of allowances held plus the fair value of additional allowances required to satisfy the obligation after adjustment for applicable no-cost allowances received. PSE includes the obligation in current liabilities and long-term liabilities reported in the "Compliance obligations" line item on the consolidated balance sheets based on the dates the allowances are to be surrendered. Consistent with ASC 980, PSE defers costs and revenues associated with the cap-and-invest program through regulatory assets and liabilities.

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 Washington Commission authorized an AFUDC rate, calculated using the allowed rate of return for utility plant additions. The AFUDC rate authorized was 7.39% effective October 1, 2020 for natural gas and October 15, 2020 for electric. Per the 2022 GRC, the AFUDC rate authorized is 7.16% effective January 7, 2023 for natural gas and January 11, 2023 for electric.

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 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 excise taxes (which are a component of general retail customer rates) and municipal taxes totaling $319.1 million and $292.8 million for 2023 and 2022, 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 soft rate cap of total revenue for decoupled rate schedules, where rate cap is applied to under-collected revenue and any over-collected revenues are passed back to customers at 100%. Any excess under-recovered revenue above the rate cap will be included in the following year's decoupled rate and the Company will only be able to recognize revenue below the rate cap of total revenue for decoupled rate schedules. For revenue deferrals exceeding the annual 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. The soft rate cap test, which limits the amount of revenues PSE can collect in its annual filings, is 5.0% for natural gas customers and 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 Credit Losses

The Company measures expected credit losses on trade receivables on a collective basis by receivable type, which include electric retail receivables, gas retail receivables, and electric wholesale receivables. The estimate of expected credit losses considers historical credit loss information that is adjusted for current conditions and reasonable and supportable forecasts.

The following table presents the activity in the allowance for credit losses for accounts receivable at December 31, 2023, and 2022:

Puget Sound Energy

(Dollars in Thousands)	Year Ended December 31,		
Allowance for credit losses:		2023	2022
Beginning balance	$	41,962 $	34,958
Provision for credit loss expense[1]		34,724	28,316
Receivables charged-off		(38,475)	(21,312)
Total ending allowance balance	$	38,211 $	41,962

[1] $17.1 million and $7.1 million of provision related to balances of deferred costs specific to COVID-19 as of December 31, 2023 and 2022, 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. The cumulative annual cost threshold for the storm loss deferral mechanism is $10.0 million. Additionally, costs may only be deferred if the outage meets the Institute of Electrical and Electronics Engineers outage criteria for system average interruption duration index and qualifying costs exceed $0.5 million per qualified storm.

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, "Derivatives and Hedging" (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 9, "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 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 10, "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.

Leases

The Company has adopted ASU 2016-02 as of January 1, 2019, which resulted in the recognition of right-of-use asset and lease liabilities that have not previously been recorded and are material to the balance sheet. Under FERC Docket AI-19-1-000, operating leases are not required to be capitalized and reported in the balance sheet accounts established for capital leases. However, a jurisdictional entity is permitted to implement the ASU's guidance to report operating leases with a lease term in excess of 12 months as right of use assets, with corresponding lease obligations, in the balance sheet accounts established for capital leases. Accordingly the Company's operating leases are recognized on the balance sheet in Account 101.1 (Property Under Capital Leases), Account 227 (Obligations Under Capital Leases- Noncurrent), and Account 243 (Obligations Under Capital Leases — Current). Adoption of the standard did not have a material impact on the income statement.

ROU assets represent the right to use an underlying asset for the lease term, and consist of the amount of the initial measurement of the lease liability, any lease payments made to the lessor at or before the commencement date, minus any lease incentives received, and any initial direct costs incurred by the lessee. Lease liabilities represent our obligation to make lease payments arising from the lease and are measured at present value of the lease payments not yet paid, discounted using the discount rate for the lease, at commencement. As most of PSE's leases do not provide an implicit interest rate, PSE uses the incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. For fleet, IT and wind farm land leases, this rate is applied using a portfolio approach. The lease terms may include options to extend or terminate the lease when it is reasonably certain that PSE will exercise that option. On the statement of income, operating leases are generally accounted for under a straight-line expense model, while finance leases, which were previously referred to as capital leases, are generally accounted for under a financing model. Consistent with the

previous lease guidance, however, the standard allows rate-regulated utilities to recognize expense consistent with the timing of recovery in rates.

PSE has lease agreements with lease and non-lease components. Non-lease components comprise common area maintenance and utilities, and are accounted for separately from lease components.

Variable Interest Entities

In April 2017, PSE entered into a power purchase agreement (PPA) with Skookumchuck Wind Energy Project, LLC (Skookumchuck) pursuant to which Skookumchuck would develop a wind generation facility and sell bundled energy and associated attributes, namely renewable energy certificates (RECs), to PSE over a term of 20 years. Skookumchuck commenced commercial operation in November 2020. In May 2020, PSE entered into a PPA with Golden Hills Wind Farm, LLC (Golden Hills) pursuant to which Golden Hills would develop a wind generation facility and sell bundled energy and associated attributes, namely RECs, to PSE over a term of 20 years. On April 29, 2022, Golden Hills commenced commercial operations. In February 2021, PSE entered into a PPA with Clearwater Wind Project, LLC (Clearwater) in which Clearwater would develop a wind generation facility and sell energy and associated attributes to PSE over a term of 25 years. On November 8, 2022, Clearwater commenced commercial operations. For each of the aforementioned PPAs, PSE has no equity investment in the generation facilities, but is the only customer of each facility. PSE has concluded that Skookumchuck, Golden Hills, and Clearwater represent variable interest entities (VIE) and that PSE is not the primary beneficiary of these VIEs since it does not control the commercial and operating activities of the facilities. Additionally, PSE does not have the obligation to absorb losses or receive benefits. As a result, PSE does not consolidate the VIEs.

Purchased energy of $86.0 million and $38.6 million were recognized in purchased electricity on the Company's consolidated statements of income for the year ended December 31, 2023 and December 31, 2022, respectively. Additionally, $14.6 million and $3.9 million were included in accounts payable on the Company's balance sheet as of December 31, 2023 and December 31, 2022, respectively.

(2) New Accounting Pronouncements

Recently Adopted Accounting Guidance

Reference Rate Reform

In March 2020, the FASB issued Accounting Standards Updated (ASU) 2020-04, *"Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*". ASU 2020-04 provides temporary optional expedients and exceptions to the current guidance on contract modifications to ease the financial reporting burdens related to the expected market transition from London Interbank Offered Rate (LIBOR) and other interbank offered rates to alternative reference rates. In December 2022, the FASB issued ASU 2022-06, *"Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848"*. ASU 2022-06 postpones the sunset date of Topic 848 from December 31, 2022 to December 31, 2024. As of December 31, 2023, the Company is not aware of any current agreements that reference LIBOR and thus, has not utilized any practical expedients. The Company continues to monitor whether any new agreements are entered into which reference LIBOR and if the expedients would be utilized through the allowed period of December 31, 2024.

Accounting Standards Issued but Not Yet Adopted

Income Tax Disclosures

In December 2023, the FASB issued ASU 2023-09, "Income Taxes (Topic 740): *Improvements to Income Tax Disclosures".* ASU 2023-09 will require disclosure of specific categories in a tabular rate reconciliation using both percentages and currency amounts, and provide additional information for reconciling items that meet a quantitative threshold. Further requirements include a qualitative description of the tax jurisdictions, an explanation of the reconciling items disclosed and disclosure regarding income taxes paid. ASU 2023-09 will eliminate the requirement to disclose the nature and estimate of range in unrecognized tax benefits and disclosures of the cumulative amount of each type of temporary difference when a deferred tax liability is not recognized. ASU 2023-09 will be effective for the Company in annual periods beginning after December 15, 2024. As the amendment contemplates changes in disclosures only, it is not expected to have a

material impact on the Company's results of operations, cash flows, or consolidated balance sheets; however, the Company continues to assess the impacts of the amendment.

(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, 2023, and 2022, are included in the following tables:

Puget Sound Energy (Dollars in Thousands)	Remaining Amortization Period	December 31, 2023	2022
Climate Commitment Act recovery	N/A	$ 186,550	$ —
Environmental remediation	(a)	182,697	141,893
Automated meter reading	20 years	104,159	—
Storm damage costs electric	3 to 5 years	95,754	127,524
PGA unrealized loss	N/A	80,376	—
Deferred Washington Commission AFUDC	30 years	58,648	61,463
Baker Dam licensing operating and maintenance costs	(b)	55,641	55,049
Chelan PUD contract initiation	7.8 years	55,523	62,611
PCA mechanism	N/A	48,427	112,207
Lower Snake River	13.4 years	43,220	48,536
Washington Commission LNG	N/A	42,247	28,335
Energy conservation costs	(a)	37,560	10,296
Unamortized loss on reacquired debt	1 to 44 years	31,626	33,732
Decoupling deferrals and interest	Less than 2 years	31,398	36,773
Get to zero depreciation expense deferral (c)	1 to 3 years	29,185	49,605
Colstrip tracker expenditures	N/A	26,253	—
Washington Commission COVID-19	N/A	17,097	7,051
Generation plant major maintenance, excluding Colstrip	2 to 9 years	16,941	20,374
Regulatory filing fee deferral	N/A	14,582	7,559
Advanced metering infrastructure	N/A	12,094	30,431
Snoqualmie licensing operating and maintenance costs	(b)	7,428	7,445
Washington Commission electric vehicle (c)	3 years	5,755	7,796
Water heater rental property loss	3 years	3,847	5,725
Colstrip major maintenance (c)	2 years	2,690	4,035
Mint Farm ownership and operating costs	1.3 years	2,317	4,317
Property tax tracker	Less than 2 years	—	12,398
Various other regulatory assets	(a)	19,963	21,283
Total PSE regulatory assets		$ 1,211,978	$ 896,438
Deferred income taxes (d)	N/A	$ (761,621)	$ (811,724)
Cost of removal	(e)	(682,058)	(639,320)
PGA liability	2 years	(132,082)	(3,536)
Repurposed production tax credits	N/A	(126,482)	(133,855)
Climate Commitment Act auction proceeds	N/A	(84,485)	—
Decoupling liability	Less than 2 years	(60,664)	(63,206)
Colstrip tracker recovery	N/A	(31,390)	—
Property tax tracker	Less than 2 years	(11,135)	—
Green direct	N/A	(10,442)	(11,837)
Bill discount rate deferral	N/A	(6,579)	—
PGA unrealized gain	N/A	—	(287,725)
Various other regulatory liabilities	(a)	(7,958)	(9,936)
Total PSE regulatory liabilities		$ (1,914,896)	$ (1,961,139)
PSE net regulatory assets (liabilities)		$ (702,918)	$ (1,064,701)

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

(b) *The FERC license requires PSE to incur various O&M expenses over the life of the 40 year and 50 year license for Snoqualmie and Baker, respectively. The regulatory asset represents the net present value of future expenditures and will be offset by actual costs incurred.*

(c) *Amortization period approved in 2022 GRC, beginning January 2023.*

(d) *For additional information, see Note 13,"Income Taxes".*

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

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 $682.1 million and $639.3 million in 2023 and 2022, respectively, for the cost of removal of utility plant. These amounts are collected from PSE’s customers through depreciation rates.

General Rate Case Filing

PSE filed a GRC which includes a two year multiyear rate plan (MYRP) with the Washington Commission on February 15, 2024, requesting an overall increase in electric and natural gas rates of 6.7% and 19.0% respectively in rate year one (expected to approximate calendar year 2025) and 8.5% and 2.1%, respectively in rate year two (expected to approximate calendar year 2026). PSE requested a return on equity of 9.95% for the first rate year beginning in 2025 and 10.5% for the second rate year beginning in 2026. PSE requested an overall rate of return of 7.65% in rate year one and 7.99% in rate year two. The filing requests recovery of forecasted plant additions through 2024 as required by RCW 80.28.425 as well as forecasted plant additions through 2026, the final year of the MYRP. The next phase of the filing will be to establish a procedural calendar for the adjudication of the case. The Company estimates the agreed upon rates from this proceeding will become effective by statute approximately 11 months after filings.

On December 22, 2022, the Washington Commission issued an order on PSE’s 2022 general rate case (GRC), which was filed on January 31, 2022, that approved a weighted cost of capital of 7.16%, or 6.62% after-tax, a capital structure of 49.0% in common equity in 2023 and 2024, and a return on equity of 9.4%. On January 6, 2023, the Washington Commission approved PSE’s natural gas rates in its compliance filing with an overall net revenue change of $70.8 million or 6.4% in 2023 and $19.5 million or 1.7% in 2024, with an effective date of January 7, 2023. On January 10, 2023, the Washington Commission approved PSE’s electric rates in its compliance filing with an overall net revenue change of $247.0 million or 10.8% in 2023 and $33.1 million or 1.3% in 2024 with an effective date of January 11, 2023. Per the 2022 GRC Final Order in Docket No. UE-220066, rates approved in PSE's power cost only rate case (PCORC) in Docket No. UE-200980 were set to zero as of January 11, 2023, and PSE agreed not to file a PCORC during 2023 and 2024, the period covered by the two-year rate plan agreed to in the GRC settlement.

Prior rates were subject to the 2019 GRC and included a weighted cost of capital of 7.39% or 6.8% after-tax, and a capital structure of 48.5% in common equity with a return on equity of 9.4%. The annualized overall rate impacts were an electric revenue increase of $48.3 million, or 2.3%, and a natural gas increase of $4.9 million, or 0.6%, effective October 1, 2021. For further information, see Note 3, "Regulation and Rates" included in the Company's FERC Form 1 for the period ended December 31, 2022.

Climate Commitment Act Deferral

On December 29, 2022, PSE filed accounting petitions with the Washington Commission requesting authorization to defer costs and revenues associated with the Company’s compliance with the Climate Commitment Act (CCA) codified in law within Revised Code of Washington (RCW) 70A.65. On February 28, 2023, in Order 01 under Docket No. UE-220974 and UG-220975, the Washington Commission granted PSE approval to defer the cost of emission allowances to comply with the CCA and the proceeds from no-cost allowances consigned to auction beginning January 1, 2023. On August 3, 2023, the Washington Commission approved PSE's request for CCA rates in Docket No. UG-230470, subject to refund, effective October 1, 2023, to recover the estimated ongoing allowance costs and proportionate pass back of credits to customers from estimated auction proceeds during the period of August 2023 through December 2023. On October 26, 2023, the Washington Commission approved PSE's request for CCA rates in Docket No. UG-230756, subject to refund, effective November 1, 2023, to recover the estimated ongoing allowance costs and proportionate pass back of credit to customers from estimated auction proceeds during the period of January 2023 through September 2023. The recovery of ongoing allowance costs and pass back of credits is consistent with the approved accounting petitions in Dockets No. UG-220975 and UG-230471. As of December 31, 2023, PSE deferred $184.4 million of CCA compliance costs for natural gas and electric liabilities. Additionally, PSE will consign for auction at least the minimum amount of no-cost emission allowances allocated for natural gas operations in compliance with the CCA, the proceeds of which will be used for the benefit of natural gas customers, as determined by the Washington Commission. PSE will not record a regulatory liability to defer the proceeds until consigned

allowances are sold at auction. As of December 31, 2023, PSE recorded $83.0 million related to the proceeds from the sale of consigned GHG emission allowances.

In October 2022, the Washington Department of Ecology (WDOE) published final regulations to implement the cap and invest program. The WDOE also indicated that it will have subsequent rulemakings building off initial rulemaking as program implementation is underway and progress with Washington State carbon goals are evaluated. One component of the CCA rules stipulates the WDOE shall provide qualifying electric utilities, such as PSE, with no-cost allowances based on the cost burden of the program to electric customers, which is derived using a forecast of emissions. An additional component of the CCA rules stipulates that the allocation of no-cost allowances may be adjusted once a year under a "true-up mechanism" which takes into account the cumulative total of no-cost allowances issued to an electric utility relative to the electric utility's reported GHG emissions. Such adjustments will be made in the fourth quarter of the following year, at which time WDOE could add allowances to an electric utility's account if such account has an allowance deficit, or withhold future allocated allowances going forward if such account had previously allocated excess allowances. WDOE has not provided further guidance or rules specifying how such adjustments will be determined. As a result, the Company cannot predict the impact of such adjustments.

WDOE provided an initial allocation of no-cost allowances to electric utilities on April 24, 2023. However, qualifying electric utilities were allowed to submit revised emissions forecasts approved by the Washington Commission to WDOE by July 30, 2023. PSE filed its revised forecast of 2023 emission under Docket No. UE 220797, which was approved by the Washington Commission on July 27, 2023, and approved by the WDOE on September 27, 2023. Accordingly, the Company's compliance obligation as of December 31, 2023, reflects the revised allowance allocation.

Following the September 27, 2023 WDOE decision, PSE's no-cost allowance allocation will be set for 2023 until the fourth quarter of 2024 when there is an opportunity to request a "true-up" of no-cost allowances under the aforementioned adjustment mechanism. However, as of December 31, 2023, due to the uncertainty around implementation of the adjustment mechanism PSE did not adjust the CCA electric compliance obligation anticipating an adjustment to no cost allowances to reported 2023 electric GHG emissions and does not plan to make such adjustment until a formal true-up allocation has been granted by the WDOE.

Revenue Decoupling Adjustment Mechanism

In June 2021, the Washington Commission approved the multi-party settlement agreement, which was filed within PSE’s PCORC filing. As part of this settlement agreement, the electric annual fixed power cost allowed revenue was updated to reflect changes in the approved revenue requirement and took effect on July 1, 2021.

In September 2021, the Washington Commission approved the 2019 GRC filing. As part of this filing, the annual electric and natural gas delivery cost allowed revenue was updated to reflect changes in the approved revenue requirement. The changes took effect on October 1, 2021.

On January 6, 2023, the Washington Commission approved the natural gas 2022 GRC filing. As part of this filing, the annual natural gas delivery allowed revenue was updated to reflect changes in the approved revenue requirement. Additionally, the Commission approved the removal of the earnings test from the decoupling mechanism in accordance with RCW 80.28.425(6). The changes took effect on January 7, 2023.

On January 10, 2023, the Washington Commission approved the electric 2022 GRC filing. As part of this filing, the annual electric delivery and fixed power cost allowed revenue was updated to reflect changes in the approved revenue requirement. Additionally, the Commission approved the removal of the earnings test from the decoupling mechanism in accordance with RCW 80.28.425(6). The changes took effect on January 11, 2023.

On December 31, 2023, 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. Based on the analyses in 2023 and 2022, no reserve adjustment was recorded as of December 31, 2023 and 2022.

Power Cost Adjustment Mechanism

PSE currently has a PCA mechanism that provides for the deferral of power costs that vary from the “power cost baseline” level of power costs. The “power cost baseline” levels are set, in part, based on normalized assumptions about weather and hydroelectric conditions. Excess power costs or savings are apportioned between PSE and its customers

pursuant to the graduated scale set forth in the PCA mechanism and will trigger a surcharge or refund when the cumulative deferral trigger is reached.

Effective January 1, 2017, the following graduated scale is used in the PCA mechanism:

Annual Power Cost Variability	Company's Share Over	Company's Share Under	Customers' Share Over	Customers' Share Under
Over or under collected up to $17 million	100%	100%	—%	—%
Over or under collected between $17 million - $40 million	35	50	65	50
Over or under collected beyond $40 million	10	10	90	90

For the year ended December 31, 2023, in its PCA mechanism, PSE over recovered its allowable costs by $51.1 million of which $24.9 million was apportioned to customers and $3.9 million of interest was accrued on the deferred customer balance. This compares to an under recovery of allowable costs of $110.1 million, for the year ended December 31, 2022, of which $74.6 million was apportioned to customers and accrued $1.5 million of interest on the total deferred customer balance.

Power Cost Adjustment Clause

PSE exceeded the $20.0 million cumulative deferral balance in its PCA mechanism in 2022. During 2022, actual power costs were higher than baseline power costs, thereby, creating an under-recovery of $110.1 million. Under the terms of the PCA's sharing mechanism for under-recovered power costs, PSE absorbed $39.0 million of the under-recovered amount, and customers were responsible for the remaining $71.1 million, or $76.4 million, including interest and adjusted for revenue sensitive items. On April 28, 2023, PSE filed the 2022 PCA report under Docket No. UE-230313 that proposed a recovery of the deferred balance, which included a revenue requirement increase of 0.9% in overall bill for all customers, with rates proposed to go into effect from December 1, 2023 through December 31, 2024.

PSE also exceeded the $20.0 million cumulative deferral balance in its PCA mechanism in 2021, as actual power costs were higher than baseline power costs, thereby creating an under-recovery of $68.0 million. PSE absorbed $31.3 million of the under-recovered amount, and customers were responsible for the remaining $36.7 million, or $38.4 million, including interest. In October 2022, the Washington Commission approved PSE's 2021 PCA report that proposes to recover the deferred balance for 2021 PCA period by keeping the current rates and allowing recovery from January 1, 2023 through November 30, 2023.

On September 29, 2023, PSE filed its variable power cost rates update as part of the 2022 GRC Order requirement under Docket No. UE-220066. The filing was approved in part on December 22, 2023, with updated rates effective January 1, 2024.

Purchased Gas Adjustment Mechanism

In October 2021, the Washington Commission approved PSE's request for PGA rates in Docket No. UG-210721, effective November 1, 2021. As part of that filing, PSE requested an annual revenue increase of $59.1 million, where PGA rates, under Schedule 101, increase annual revenue by $80.6 million, and the tracker rates under Schedule 106, decrease annual revenue by $21.5 million. Those annual 2021 PGA rate increases were set in addition to continuing the collection on the remaining balance of $69.4 million under Supplemental Schedule 106B, which were set, in effect, through September 30, 2023, per the 2019 GRC.

In October 2022, the Washington Commission approved PSE's request for PGA rates in Docket No. UG-220715, effective November 1, 2022. As part of that filing, PSE requested an annual revenue increase of $155.3 million, where PGA rates, under Schedule 101, increase annual revenue by $142.1 million, and the tracker rates under Schedule 106, increase annual revenue by $13.2 million.

In November 2022, the FERC approved a settlement of a counterparty, FERC Docket No. RP17-346. Under the terms, PSE was allocated $24.2 million related to PSE natural gas services which was recorded on December 31, 2022, and included below. The 2022 GRC order requires PSE to amortize the refund in 2023 as a credit against natural gas costs and therefore pass back the refund to customers through the PGA mechanism.

On October 26, 2023, the Washington Commission approved PSE's request for PGA rates in Docket No. UG-230769, effective November 1, 2023. As part of that filing, PSE requested an annual revenue decrease of $309.4 million, where PGA rates, under Schedule 101, decrease annual revenue by $93.9 million, and the tracker rates under Schedule 106, decrease annual revenue by $215.5 million. The annual 2023 PGA rate decreases include the aforementioned counterparty settlement pass back of $28.1 million under Supplemental Schedule 106B.

The following table presents the PGA mechanism balances and activity at December 31, 2023 and December 31, 2022:

Puget Sound Energy

(Dollars in Thousands) PGA receivable balance and activity	At December 31, 2023	At December 31, 2022
PGA receivable beginning balance	$ (3,536)	$ 57,935
Actual natural gas costs	404,897	457,950
Allowed PGA recovery	(521,882)	(496,879)
Interest	(7,639)	1,674
Refund from counterparty settlement	(3,922)	(24,216)
PGA (liability)/receivable ending balance	$ (132,082)	$ (3,536)

Storm Loss Deferral Mechanism

The Washington Commission has defined deferrable weather-related events and provided that costs in excess of the annual cost threshold may be deferred for qualifying damage costs that meet the modified Institute of Electrical and Electronics Engineers outage criteria for system average interruption duration index. For the year ended December 31, 2023, PSE incurred $8.1 million in weather-related electric transmission and distribution system restoration costs, of which the Company deferred zero and $2.1 million as regulatory assets related to storms that occurred in 2023 and 2022, respectively. This compares to $32.2 million incurred in weather-related electric transmission and distribution system restoration costs for the year ended December 31, 2022, of which the Company deferred $21.4 million and $0.2 million as regulatory assets related to storms that occurred in 2022 and 2021, respectively. Under the 2017 GRC Order, the storm loss deferral mechanism approved the following: (i) the cumulative annual cost threshold for deferral of storms under the mechanism at $10.0 million; 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 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 WDOE and/or other third parties as potentially responsible or liable at several contaminated sites, including former 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. The adjustments recorded are based on the best estimate or the low end of a range of reasonably possible costs expected to be incurred by the Company based on its currently understood legal exposure at applicable sites. It is reasonably possible that incurred costs exceed the recorded amounts due to changes in laws and/or regulations, higher than expected costs due to changes in labor market or supply chain, evolving technology, unforeseen and/or the discovery of new or additional contamination. The Company currently estimates that a significant portion of its past and future environmental remediation costs are recoverable from insurance companies, from third parties, and/or from customers under a Washington Commission order. The Company is subject to cost-sharing agreements with third parties regarding environmental remediation projects in Seattle, Tacoma, Everett, and Bellingham, Washington. As of December 31, 2023, the Company's share of future remediation costs is estimated to be approximately $72.9 million.

The following table summarizes changes in the Company's environmental remediation regulatory assets for the years ended December 31, 2023, and 2022:

Puget Sound Energy

(Dollars in Thousands)	Year Ended December 31, 2023	Year Ended December 31, 2022
Environmental remediation regulatory asset beginning balance	$ 141,893	$ 127,977
Remediation cost amortization, net of recoveries	(4,521)	(1,226)
Changes in estimates[1]	45,325	15,142
Environmental remediation regulatory asset ending balance	$ 182,697	$ 141,893

[1] *Driven in significant part by the Quendall Terminals site on Lake Washington in Renton, Washington. The site represents contaminated facilities from a long defunct creosote manufacturer which had purchased waste products from PSE predecessors. In addition, it was driven by an increase in estimate at the shared site of Gas Works Park on Lake Union in Seattle, Washington, which was previously a gas manufacturing plant.*

The following table summarizes changes in the Company's environmental remediation liabilities for the years ended December 31, 2023, and 2022:

Puget Sound Energy

(Dollars in Thousands)	Year Ended December 31, 2023	Year Ended December 31, 2022
Environmental remediation liabilities beginning balance	$ 135,052	$ 119,929
Payments made, net of recoveries	(495)	(1,343)
Changes in estimates[1]	45,883	16,466
Environmental remediation liabilities ending balance	$ 180,440	$ 135,052

[1] *Driven in significant part by the Quendall Terminals site on Lake Washington in Renton, Washington. The site represents contaminated facilities from a long defunct creosote manufacturer which had purchased waste products from PSE predecessors. In addition, it was driven by an increase in estimate at the shared site of Gas Works Park on Lake Union in Seattle, Washington, which was previously a gas manufacturing plant.*

(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, 2023, approximately $1.7 billion 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 48.1% at December 31, 2023, and the EBITDA to interest expense was 5.2 to 1.0 for the twelve months ended December 31, 2023.

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, 2023, 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[1] (Years)	Puget Sound Energy December 31, 2023	2022
Distribution plant	7-65	$ 9,804,018	$ 9,406,017
Production plant	3-90	3,805,294	3,780,910
Transmission plant	44-75	1,701,878	1,683,737
General plant	5-75	738,996	760,094
Intangible plant (including capitalized software)[2]	3-50	577,291	745,973
Plant acquisition adjustment	N/A	282,792	282,792
Underground storage	25-60	60,171	58,716
Liquefied natural gas storage	25-50	226,208	14,498
Plant held for future use	N/A	59,561	46,232
Recoverable Cushion Gas	N/A	8,784	8,784
Plant not classified	N/A	1,032,002	723,383
Finance leases, net of accumulated amortization[3]	N/A	95,114	99,967
Less: accumulated provision for depreciation		(6,954,968)	(6,688,033)
Subtotal		$ 11,437,141	$ 10,923,070
Construction work in progress		1,156,265	861,801
Net utility plant		$ 12,593,406	$ 11,784,871

1. *Estimated Useful Life years have been approved in the 2022 GRC.*
2. *Intangible assets include capitalized software and franchise agreements with useful lives ranging between 3-10 years and 10-50 years, respectively.*
3. *At December 31, 2023, and 2022, accumulated amortization of finance leases at PSE was $13.2 million and $7.3 million, respectively.*

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 table indicates the Company's percentage ownership and the extent of the Company's investment in jointly owned generating plants in service at December 31, 2023. 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 3 & 4	Coal	25.00 %	$ 580,451	$ —	$ (464,725)
Frederickson 1	Natural Gas	49.85	73,658	—	(32,795)
Jackson Prairie	Natural Gas	33.34	60,171	2,100	(27,986)
Tacoma LNG	Natural Gas	various	247,073	119	(11,600)

On September 2, 2022, PSE and Talen Energy reached an agreement to transfer PSE's ownership interest in Colstrip Units 3 and 4 to Talen Energy on December 31, 2025. Management evaluated Colstrip Units 3 and 4 and determined that the applicable held for sale and abandonment accounting criteria were not met as of December 31, 2023. As such, Colstrip Units 3 and 4 are classified as Electric Utility Plant on the Company's balance sheet as of December 31, 2023.

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, liquefied natural gas storage sites, and leased facilities where disposal is governed by ASC 410-20 "Asset Retirement and Environmental Obligations" (ARO). The Company records its ARO liabilities for its electric transmission and distribution poles as well as gas distribution mains aligned with its underlying asset data with future estimates of retirements.

For the twelve months ended December 31, 2023 and 2022, the Company reviewed the estimated remediation costs at Colstrip and determined no change was warranted for the Colstrip ARO liability for Colstrip Units 1 and 2 and Colstrip Units 3 and 4. For the twelve months ended December 31, 2023 and 2022, the Company recorded relief of ARO and environmental remediation liability of $6.0 million and $6.9 million, respectively.

In addition, the Company recorded Tacoma LNG facility ARO liability of $4.1 million and $3.9 million for PSE as of December 31, 2023 and December 31, 2022, respectively. In 2023, the ARO liability associated with the Tacoma LNG facility was fully recorded as construction was completed.

Puget Sound Energy (Dollars in Thousands)	December 31, 2023	2022
Asset retirement obligation at beginning of the period	$ 205,559	$ 205,338
Relief of liability	(5,998)	(6,867)
Revisions in estimated cash flows	(2,206)	1,519
Accretion expense	5,682	5,569
Asset retirement obligation at end of period	$ 203,037	$ 205,559

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, 2023:

- 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 the FERC orders the project to be decommissioned, although PSE contends that the 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.

Beaver Creek Wind Project

Beaver Creek is a utility-scale wind project located in Stillwater County, Montana, with an expected nameplate capacity of 248 MW that is expected to commence commercial operations in 2025. On September 15, 2023, PSE executed a membership interest purchase agreement with Caithness Beaver Creek, LLC for a 100% ownership interest in Caithness Montana Wind, LLC, which closed on December 1, 2023. Total consideration is expected to be $44.6 million of which $23.8 million has been paid as of December 31, 2023 and the remaining balance is expected to be paid in the first quarter of 2025. On December 1, 2023, PSE entered into a turbine supply agreement with GE Renewables North America, LLC to purchase 88 wind turbines. Total consideration is expected to be $266.9 million of which $213.5 million has been paid as of December 31, 2023 and the remaining balance is expected to paid throughout 2024 and the first quarter of 2025 as turbines are delivered and the project is completed. As of December 31, 2023, $283.9 million was recorded to construction work in progress in conjunction with the Beaver Creek wind project.

On January 26, 2024, PSE entered into a balance of plant agreement to complete the design and construction of the project. Total consideration is expected to be approximately $129.4 million.

(6) Long-Term Debt

The following table presents outstanding long-term debt due dates and principal amounts, net of debt discount, issuance and other costs as of 2023 and 2022:

(Dollars in Thousands) Series	Type	Due	December 31, 2023	2022
Puget Sound Energy:				
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	600,000
3.250%	Senior Secured Note	2049	450,000	450,000
2.893%	Senior Secured Note	2051	450,000	450,000
4.700%	Senior Secured Note	2051	45,000	45,000
5.448%	Senior Secured Note	2053	400,000	—
*	Debt discount, issuance cost and other	*	(39,813)	(37,095)
Total PSE long-term debt			$ 5,184,047	$ 4,786,765

* *Not Applicable.*

PSE's senior secured notes will cease to be secured by the pledged first mortgage bonds on the date (the "Substitution 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, 2023, the latest maturity date of the first mortgage bonds, other than pledged first mortgage bonds, is December 22, 2025. On the Substitution Date, PSE will deliver to the trustee for PSE's senior secured notes substitute pledged first mortgage bonds to be issued under a new mortgage indenture. As a result, as of the Substitution Date PSE's outstanding senior secured notes and any future series of PSE's senior secured notes will be secured by substitute pledged first mortgage bonds.

Puget Sound Energy Long-Term Debt

In August 2022, PSE filed an S-3 shelf registration statement under which it may issue up to $1.4 billion aggregate principal amount of senior notes secured by first mortgage bonds. As of the date of this report, $1.0 billion was available to be issued. The shelf registration will expire in August 2025.

On May 18, 2023, PSE issued $400.0 million of green senior secured notes at an interest rate of 5.448%. The notes mature on June 1, 2053 and pay interest semi-annually in arrears on June 1 and December 1 of each year, commencing December 1, 2023. Net proceeds from the issuance of the notes were deposited into the Company's general account and are intended to be used for allocation to eligible projects, as defined in PSE's sustainable financing framework, which was published in May 2023. Eligible projects are expenditures incurred and investments made related to development and acquisition of some or all of the following types of projects: (i) renewable energy, (ii) energy efficiency, (iii) clean transportation, (iv) biodiversity conservation, (v) climate change adaptation, (vi) water and wastewater management, (vii) pollution prevention and control, and (viii) green innovation.

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)	2024	2025	2026	2027	2028	Thereafter	Total
Maturities of:							
PSE	$ —	$ 17,000	$ —	$ 300,000	$ —	$ 4,906,860	$ 5,223,860
Total long-term debt	$ —	$ 17,000	$ —	$ 300,000	$ —	$ 4,906,860	$ 5,223,860

(7) Liquidity Facilities and Other Financing Arrangements

As of December 31, 2023, and 2022, PSE had $336.6 million and $357.0 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 2023 and 2022 was 9.0% and 6.1%, respectively. As of December 31, 2023, PSE had several committed credit facilities that are described below.

Puget Sound Energy

Credit Facility

In May 2022, PSE entered into a new $800.0 million credit facility to replace the existing facility. The terms and conditions, including fees, financial covenant, expansion feature and credit spreads remain substantially the same. The base interest rate on loans has changed to the Secured Overnight Financing Rate (SOFR), as the London Interbank Offer Rate (LIBOR) was discontinued on June 30, 2023. The proceeds of the PSE credit facility are to be used for general corporate purposes. The maturity date of the credit facility is May 14, 2027. The credit facility includes a swingline feature allowing same day availability on borrowings up to $75.0 million and has an expansion feature which, upon receipt of commitments from one or more lenders, could increase the total size of the facility up to $1.4 billion.

The credit agreement is syndicated among numerous lenders and contains usual and customary affirmative and negative covenants that, among other things, place 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 leverage ratio that requires the ratio of (a) total funded indebtedness to (b) total capitalization to be 65.0% or less at all times. PSE certifies its compliance with such covenants to participating banks each quarter. As of December 31, 2023, PSE was in compliance with all applicable covenant ratios.

The credit agreement allows PSE to borrow at a prime based rate or to make floating rate advances at the SOFR, in either case, 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, interest was calculated as SOFR plus 0.10% SOFR adjustment plus 1.25% spread over the adjusted SOFR rate and the commitment fee was 0.175%. As of December 31, 2023, no amount was drawn under PSE's credit facility and $336.6 million was outstanding under the commercial paper program.

Outside of the credit facility, PSE maintains a standby letter of credit with TD Bank allowing for standby letter of credit postings of up to $150.0 million as a condition of transacting on the ICE NGX platform as well as participating in the Washington state carbon allowance auctions. As of December 31, 2023, $51.0 million was issued under a standby letter of credit in support of natural gas and carbon allowance purchases. Additionally, PSE had a $2.1 million letter of credit in support of a long-term transmission contract.

Demand Promissory Note

In May 2023, PSE amended and restated its 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 $200.0 million from Puget Energy subject to approval by Puget Energy. Under the terms of the Note, PSE pays interest based on Puget Energy’s credit facility interest rate, which is SOFR plus 0.10% SOFR adjustment, plus 1.75% spread over the adjusted SOFR rate. As of December 31, 2023, there was no outstanding balance under the promissory note.

(8) Leases

PSE has operating leases for buildings for corporate offices and operations, real estate for operating facilities and the PSE LNG facility, land for our wind farms, and vehicles for PSE’s fleet. Finance leases represent office printers and office buildings. The leases have remaining lease terms of less than a year to 46 years. PSE's right-of-use (ROU) assets and lease liabilities include options to extend leases when it is reasonably certain that PSE will exercise that option.

The components of lease cost were as follows:

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2023	2022
Finance lease cost:		
Amortization of right-of-use asset	$ 3,891	$ 2,465
Interest on lease liabilities	3,237	2,482
Total finance lease cost	$ 7,128	$ 4,947
Operating lease cost	$ 22,240	$ 22,471

Supplemental cash flow information related to leases was as follows:

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2023	2022
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flow for operating leases	$ 15,990	$ 16,574
Investing cash flow for operating leases	6,250	5,896
Operating cash flow for finance leases	3,237	2,482
Financing cash flow for finance leases	3,891	2,465
Non-cash disclosure upon commencement of new lease		
Right-of-use assets obtained in exchange for new operating lease liabilities	$ 10,462	$ 5,338
Right-of-use assets obtained in exchange for new finance lease liabilities	1,245	—
Non-cash disclosure upon modification of existing lease		
Modification of operating lease right-of-use assets	$ 6,912	$ 21,068

Supplemental balance sheet information related to leases was as follows:

Puget Sound Energy

(Dollars in Thousands)	At December 31,	
Operating Leases	2023	2022
Operating lease right-of-use asset	$ 194,321	$ 193,509
Operating leases liabilities current	$ 21,629	$ 20,342
Operating lease liabilities long-term	180,754	181,265
Total operating lease liabilities	$ 202,383	$ 201,607
Finance Leases		
Common plant	$ 55,756	$ 58,391
Electric plant	39,358	41,576
Total finance lease assets	$ 95,114	$ 99,967
Other current liabilities	$ 3,371	$ 3,167
Finance lease liabilities	99,512	102,518
Total finance lease liabilities	$ 102,883	$ 105,685
Weighted Average Remaining Lease Term		
Operating leases	21.3 Years	22.0 Years
Finance leases	18.0 Years	19.1 Years
Weighted Average Discount Rate		
Operating leases	3.75 %	3.62 %
Finance leases	3.08 %	3.07 %

The following table summarizes the Company's estimated future minimum lease payments as of December 31, 2023:

Maturities of lease liabilities (Dollars in Thousands)	Future Minimum Lease Payments	
At December 31,	Operating Leases	Finance Leases
2024	$ 24,390	$ 6,586
2025	24,284	6,648
2026	23,896	6,709
2027	23,497	6,731
2028	20,708	6,670
Thereafter	164,820	103,079
Total lease payments	$ 281,595	$ 136,423
Less imputed interest	(79,212)	(33,540)
Total net present value	$ 202,383	$ 102,883

(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 (Dollars in Thousands)	Year Ended December 31,					
	Volumes (millions)		Assets[1]		Liabilities[2]	
	2023	2022	2023	2022	2023	2022
Electric portfolio derivatives	*	*	$ 93,028	$ 337,703	$ 126,939	$ 87,120
Natural gas derivatives (MMBtus)[3]	301	322	16,521	343,947	96,898	56,222
Total derivative contracts			$ 109,549	$ 681,650	$ 223,837	$ 143,342
Current			$ 74,225	$ 587,029	$ 185,788	$ 124,976
Long-term			35,324	94,621	38,049	18,366
Total derivative contracts			$ 109,549	$ 681,650	$ 223,837	$ 143,342

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 315.6 million One Million British Thermal Units (MMBtus) and purchased electricity of 2.3 million megawatt hours (MWhs) at December 31, 2023, and 234.9 million MMBtus and 5.3million MWhs at December 31, 2022.*

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 10, "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

December 31, 2023						
				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(Dollars in Thousands)	Gross Amount Recognized in the Consolidated Balance Sheet[1]	Gross Amounts Offset in the Consolidated Balance Sheet	Net of Amounts Presented in the Consolidated Balance Sheet	Commodity Contracts[2]	Cash Collateral Received/Pledged	Net Amount
Assets:						
Energy derivative contracts	$ 109,549	$ —	$ 109,549	$ (82,206)	$ —	$ 27,343
Liabilities:						
Energy derivative contracts	223,837	—	223,837	(82,206)	(84)	$ 141,547

December 31, 2022						
				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(Dollars in Thousands)	Gross Amount Recognized[1]	Gross Amounts Offset in the Consolidated Balance Sheet	Net of Amounts Presented in the Consolidated Balance Sheet	Commodity Contracts[2]	Cash Collateral Received/Pledged	Net Amount
Assets:						
Energy derivative contracts	$ 681,650	$ —	$ 681,650	$ (125,334)	$ —	$ 556,316
Liabilities:						
Energy derivative contracts	143,342	—	143,342	(125,334)	(5,661)	$ 12,347

1. *All derivative contract deals are executed under ISDA, NAESB and WSPP master agreements with right of set-off.*
2. *Amounts reflect netting by Counterparty and right of set-off.*

The following table presents 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		Year Ended December 31,	
(Dollars in Thousands)	Location	2023	2022
Gas for power derivatives:			
Unrealized	Unrealized gain (loss) on derivative instruments, net	$ (155,774)	$ 61,761
Realized	Electric generation fuel	47,930	158,550
Power derivatives:			
Unrealized	Unrealized gain (loss) on derivative instruments, net	(128,721)	199,416
Realized	Purchased electricity	69,136	20,917
Total gain (loss) recognized in income on derivatives		$ (167,429)	$ 440,644

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 swap 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, 2023, approximately 98.8% 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 1.2% 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 in the determination of reserves, such as credit default swaps and bond spreads. 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, 2023, 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, 2023, PSE had cash posted as collateral of $12.4 million related to contracts executed on the ICE platform. As a condition of transacting on the ICE NGX platform as well as participating in the Washington state carbon allowance auctions, PSE maintains a standby letter of credit agreement with TD Bank. As of December 31, 2023, PSE had no cash posted with ICE NGX, and $51.0 million was issued under the standby letter of credit agreement in support of natural gas and carbon allowance purchases. PSE did not trigger any collateral requirements with any of its counterparties nor were any of PSE's counterparties required to post collateral resulting from credit rating downgrades during the twelve months ended December 31, 2023.

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	December 31,					
(Dollars in Thousands)	2023			2022		
Contingent Feature	Fair Value[1] Liability	Posted Collateral	Contingent Collateral	Fair Value[1] Liability	Posted Collateral	Contingent Collateral
Credit rating[2]	$ 13,384	$ —	$ 13,384	$ 3,157	$ —	$ 3,157
Requested credit for adequate assurance	53,427	—	—	4,157	—	—
Forward value of contract[3]	84	12,429	N/A	5,661	56,200	N/A
Total	$ 66,895	$ 12,429	$ 13,384	$ 12,975	$ 56,200	$ 3,157

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 or that are transacted at illiquid delivery locations 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 $44.6 million and $55.0 million at December 31, 2023, and 2022, 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 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		December 31, 2023		December 31, 2022	
(Dollars in Thousands)	Level	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial liabilities:					
Long-term debt (fixed-rate), net of discount[1]	2	$ 5,184,047	$ 5,007,483	$ 4,786,765	$ 4,379,010
Total		$ 5,184,047	$ 5,007,483	$ 4,786,765	$ 4,379,010

1. *The carrying value includes debt issuances costs of $21.2 million and $21.4 million for December 31, 2023, and 2022, 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 December 31, 2023			Fair Value December 31, 2022		
(Dollars in Thousands)	Level 2	Level 3	Total	Level 2	Level 3	Total
Assets:						
Electric derivative instruments	$ 42,254	$ 50,774	$ 93,028	$ 218,610	$ 119,093	$ 337,703
Gas derivative instruments	11,647	4,874	16,521	342,988	959	343,947
Total derivative assets	$ 53,901	$ 55,648	$ 109,549	$ 561,598	$ 120,052	$ 681,650
Liabilities:						
Electric derivative instruments	$ 103,427	$ 23,512	$ 126,939	$ 84,105	$ 3,015	$ 87,120
Gas derivative instruments	95,875	1,023	96,898	55,136	1,086	56,222
Compliance obligation	168,879	—	168,879	—	—	—
Total derivative liabilities	$ 368,181	$ 24,535	$ 392,716	$ 139,241	$ 4,101	$ 143,342

Puget Sound Energy Level 3 Roll-Forward Net Asset(Liability) (Dollars in Thousands)	Year Ended December 31, 2023			2022		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Balance at beginning of period	$ 116,078	$ (127)	$ 115,951	$ (42,752)	$ (2,120)	$ (44,872)
Changes during period						
Realized and unrealized energy derivatives:						
Included in earnings[1]	(56,656)	—	(56,656)	180,533	—	180,533
Included in regulatory assets / liabilities	—	4,906	4,906	—	301	301
Settlements[2]	(32,377)	(1,098)	(33,475)	(21,972)	1,369	(20,603)
Transferred into Level 3	—	—	—	—	—	—
Transferred out Level 3	217	170	387	269	323	592
Balance at end of period	$ 27,262	$ 3,851	$ 31,113	$ 116,078	$ (127)	$ 115,951

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 $(17.3) million and $147.1 million for the years ended December 31, 2023 and 2022, respectively.*
2. *The Company had no purchases or sales of options 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, 2023 and 2022. The Company does 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 adjusts the price for transportation costs to 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, 2023:

Puget Sound Energy	Fair Value				Range		
(Dollars in Thousands)	Assets[1]	Liabilities[1]	Valuation Technique	Unobservable Input	Low	High	Weighted
Electricity	$ 50,774	$ 23,512	Discounted cash flow	Power Prices (per MWh)	$ 69.51	$ 188.63	$ 99.55
Natural Gas	$ 4,874	$ 1,023	Discounted cash flow	Natural Gas Prices (per MMBtu)	$ 2.20	$ 6.28	$ 3.55

[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, 2023, 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 $16.9 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 $28.9 million and $25.2 million for the years 2023 and 2022, 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:

1. 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.
2. 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:

1. 401(k) Company Matching: For non-represented, UA-represented and IBEW-represented employees PSE will match: 100% match on the first 3.0% of pay contributed and 50.0% match on the next 3.0% of pay contributed, such that an employee who contributes 6.0% of pay will receive 4.5% of pay in company match. Company matching will be immediately vested.
2. Company Contribution: UA-represented employees will receive an annual company contribution of 4.0% of eligible pay placed in the Cash Balance retirement plan. 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. 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. For employees hired prior to 2014, 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. Effective January 1, 2014, all new UA represented employees hired or rehired receive annual pay credits of 4.0% of eligible pay each year in the cash balance formula of the defined pension plan. Effective January 1, 2014 for non-represented employees, and December 12, 2014 for employees represented by the IBEW, newly hired or rehired employees receive annual employer contributions of 4.0% of eligible pay each year into the cash balance formula of the defined benefit pension or 401k plan account. PSE also has a non-qualified Supplemental Executive Retirement Plan (SERP) for certain key senior management employees that closed to new participants in 2019. Effective 2019, PSE has an officer restoration benefit for new officers who join PSE or are promoted, such that company contributions under PSE's applicable tax-qualified plan, which otherwise would have been credited if not for IRS limitations, are credited at 4.0% of earnings to an account with the Deferred Compensation Plan.

In addition to providing pension benefits, PSE provides legacy group health care and life insurance benefits (Other Benefits) for certain retired employees. The group health care benefit is provided via a Retiree Health Reimbursement Account (HRA) Plan effective January 1, 2020. The life insurance benefits are provided principally through an insurance company.

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, 2023, and 2022:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2023	2022	2023	2022	2023	2022
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 589,278	$ 834,960	$ 32,046	$ 43,155	$ 9,015	$ 11,654
Amendments	—	—	—	—	78	38
Service cost	18,530	26,351	143	557	184	217
Interest cost	32,375	24,263	1,589	1,253	439	311
Curtailment loss / (gain)	—	—	(2,772)			
Actuarial loss (gain)	8,469	(215,005)	(661)	(5,260)	(52)	(2,397)
Benefits paid	(38,258)	(80,226)	(3,521)	(7,659)	(1,067)	(808)
Administrative expense	(1,291)	(1,065)	—	—	—	—
Benefit obligation at end of period	$ 609,103	$ 589,278	$ 26,824	$ 32,046	$ 8,597	$ 9,015

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2023	2022	2023	2022	2023	2022
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 658,533	$ 898,550	$ —	$ —	$ 5,190	$ 6,341
Actual return on plan assets	109,028	(176,537)	—	—	543	(550)
Employer contribution	18,000	18,000	3,521	7,659	419	207
Benefits paid	(38,258)	(80,226)	(3,521)	(7,659)	(1,067)	(808)
Administrative expense	(1,292)	(1,254)	—	—	—	—
Fair value of plan assets at end of period	$ 746,011	$ 658,533	$ —	$ —	$ 5,085	$ 5,190
Funded status at end of period	$ 136,908	$ 69,255	$ (26,824)	$ (32,046)	$ (3,512)	$ (3,825)

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2023	2022	2023	2022	2023	2022
Amounts recognized in Consolidated Balance Sheet consist of:						
Noncurrent assets	$ 136,908	$ 69,255	$ —	$ —	$ —	$ —
Current liabilities	—	—	(1,978)	(3,532)	(225)	(252)
Noncurrent liabilities	—	—	(24,846)	(28,514)	(3,287)	(3,573)
Net assets (liabilities)	$ 136,908	$ 69,255	$ (26,824)	$ (32,046)	$ (3,512)	$ (3,825)

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2023	2022	2023	2022	2023	2022
Change in plan obligation and plan asset:						
Projected benefit obligation	$ 609,103	$ 589,278	$ 26,824	$ 32,046	$ 8,597	$ 9,015
Accumulated benefit obligation	601,981	582,538	26,824	29,763	8,487	8,929
Fair value of plan assets	746,011	658,533	—	—	5,085	5,190

The following tables summarize PSE's pension benefit amounts recognized in accumulated other comprehensive income (AOCI) for the years ended December 31, 2023, and 2022:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2023	2022	2023	2022	2023	2022
Amounts recognized in Accumulated Other Comprehensive Income consist of:						
Net loss (gain)	$ 74,851	$ 124,767	$ (1,613)	$ 1,864	$ (2,124)	$ (2,056)
Prior service cost (credit)	—	—	—	289	310	258
Total	$ 74,851	$ 124,767	$ (1,613)	$ 2,153	$ (1,814)	$ (1,798)

The following table summarizes PSE's net periodic benefit cost for the years ended December 31, 2023 and 2022:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2023	2022	2023	2022	2023	2022
Components of net periodic benefit cost:						
Service cost	$ 18,530	$ 26,351	$ 143	$ 557	$ 184	$ 217
Interest cost	32,375	24,263	1,589	1,253	439	311
Expected return on plan assets	(50,641)	(51,016)	—	—	(297)	(379)
Amortization of prior service cost (credit)	—	—	144	289	28	22
Amortization of net loss (gain)	—	15,080	44	2,648	(230)	(35)
Net periodic benefit cost	$ 264	$ 14,678	$ 1,920	$ 4,747	$ 124	$ 136

The following table summarizes PSE's benefit obligations recognized in other comprehensive income (OCI) for the years ended December 31, 2023 and 2022:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2023	2022	2023	2022	2023	2022
Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:						
Net loss (gain)	$ (49,916)	$ 12,736	$ (3,433)	$ (5,260)	$ (298)	$ (1,468)
Amortization of net (loss) gain	—	(15,080)	(44)	(2,648)	230	35
Settlements, mergers, sales, and closures	—	—	(145)	(331)	—	—
Prior service cost (credit)	—	—	—	—	79	38
Amortization of prior service (cost) credit	—	—	(144)	(289)	(28)	(22)
Total change in other comprehensive income for year	$ (49,916)	$ (2,344)	$ (3,766)	$ (8,528)	$ (17)	$ (1,417)

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, 2024, are expected to be at least $18.0 million, $2.0 million and $0.2 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	2023	2022	2023	2022	2023	2022
Discount rate	5.30%	5.60%	5.30%	5.60%	5.30%	5.60%
Rate of compensation increase	4.50	4.50	4.50	4.50	4.50	4.50
Interest crediting rate	4.00	4.00	N/A	N/A	N/A	N/A
Benefit Cost Assumptions						
Discount rate	5.60	3.00	5.60	3.00	5.60	3.00
Return on plan assets	6.75	6.50	—	—	7.00	7.00
Rate of compensation increase	4.50	4.50	4.50	4.50	4.50	4.50
Interest crediting rate	4.00	4.00	N/A	N/A	N/A	N/A

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 the FTSE Pension Discount Curve (formerly known as the 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. The Company's projected benefit obligation for pension plans experienced an actuarial loss of $8.5 million in 2023. This is primarily due to the change of census data, which increases the expected benefit obligation.

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)	2024	2025	2026	2027	2028	2029-2033
Qualified Pension total benefits	$ 43,500	$ 44,500	$ 45,400	$ 46,100	$ 46,700	$ 243,900
SERP Pension total benefits	1,978	7,058	2,347	4,517	1,673	7,908
Other Benefits total	868	841	828	819	816	3,589

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	22 %	28 %	35 %
Domestic small cap equity	—	8	12
Non-U.S. equity	10	24	30
Fixed income	30	40	50
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, 2023, and 2022:

	Recurring Fair Value Measures				Recurring Fair Value Measures			
	December 31, 2023				December 31, 2022			
(Dollars in Thousands)	Level 1	Level 2	Other	Total	Level 1	Level 2	Other	Total
Assets:								
Common Stock								
– Domestic	$130,288	$281	$—	$130,569	$175,969	$298	$—	$176,267
– Foreign	13,767	—	—	13,767	17,767	—	—	17,767
Government Securities	73,243	12,709	—	85,952	61,693	8,828	—	70,521
Corporate Securities								
– Domestic	—	14,787	—	14,787	—	16,005	—	16,005
– Foreign	—	8,829	—	8,829	—	6,525	—	6,525
Mutual Funds	81,130	—	—	81,130	—	—	—	—
Cash and cash equivalents	2,846	236	—	3,082	4,678	(632)	—	4,046
Investments measured at NAV								
- Collective Investment Funds	—	—	297,780	297,780	—	—	262,910	262,910
- Partnership	—	—	91,845	91,845	—	—	86,827	86,827
- Mutual Funds	—	—	48,116	48,116	—	—	46,005	46,005
- Other	—	—	128	128	—	—	846	846
Net (payable) receivable	—	—	(29,974)	(29,974)	—	—	(29,186)	(29,186)
Total assets	$301,274	$36,842	$407,895	$746,011	$260,107	$31,024	$367,402	$658,533

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:

	Recurring Fair Value Measures				Recurring Fair Value Measures			
	December 31, 2023				December 31, 2022			
(Dollars in Thousands)	Level 1	Level 2	Other	Total	Level 1	Level 2	Other	Total
Assets:								
Mutual fund	$ —	$ 5,085	$ —	$ 5,085	$ —	$ 5,190	$ —	$ 5,190
Total assets	$ —	$ 5,085	$ —	$ 5,085	$ —	$ 5,190	$ —	$ 5,190

The following discussion provides information regarding the methods used in valuation of the various asset class investments held for the pension and other postretirement benefit plans.

- Mutual funds classified as Level 1 securities have pricing inputs that are based on quoted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and New York Stock Exchange (NYSE). Mutual fund assets not included in the fair value hierarchy are privately held funds. These funds are not actively traded and utilize net asset value (NAV) as a practical expedient to measure fair value.
- Common stock investments are traded in active markets on national and international securities exchanges and are valued at closing prices on the last business day of each period presented. They are classified as Level 1 securities.
- Corporate and some government debt securities are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings. Some government debt securities have quoted prices such as certain treasury securities and are classified as Level 1 securities.
- Cash and cash equivalents comprise mostly of money market funds and foreign currency held. Money market funds are classified as Level 1 instruments as pricing inputs are based on unadjusted prices in an active market while foreign currency held is classified as a Level 2 investment based on inputs that are indirectly observable.
- Investments in collective trust funds and partnerships are stated at the NAV as determined by the issuer of fund and are based on the fair value of the underlying investments held by the fund less its liabilities. The NAV is used as a practical expedient to estimate fair value. These funds are primarily invested in a blend of corporate and government debt securities as well as international equities.

(13) Income Taxes

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

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2023	2022
Charged to operating expenses:		
Current:		
Federal	$ 112,168	$ 81,597
State	1,626	869
Deferred:		
Federal	(120,453)	(2,243)
State	—	—
Total income tax expense	$ (6,659)	$ 80,223

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

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2023	2022
Income taxes at the statutory rate	$ 26,136	$ 119,962
Increase (decrease):		
Utility plant differences[1]	$ (23,806)	$ (23,028)
AFUDC, net	(4,017)	(3,567)
Treasury grant amortization	(750)	(5,717)
Excess deferred tax amortization	(8,689)	(13,722)
State taxes, net	1,291	689
Other–net	3,176	5,606
Total income tax expense	$ (6,659)	$ 80,223
Effective tax rate	(5.4)%	14.0 %

1. Utility plant differences include the reversal of excess deferred taxes using the average rate assumption method in the amount of $27.8 million and $27.2 million in 2023 and 2022, respectively..

The Company's net deferred tax liability at December 31, 2023, and 2022, is composed of amounts related to the following types of temporary differences:

Puget Sound Energy	At December 31,	
(Dollars in Thousands)	2023	2022
Utility plant and equipment	$ 1,796,476	$ 1,852,644
Unrealized gain on derivative instruments	23,005	143,147
Other deferred tax liabilities	298,248	281,593
Subtotal deferred tax liabilities	2,117,729	2,277,384
Net regulatory liability for income taxes	(761,621)	(811,724)
Other deferred tax assets	(275,336)	(324,079)
Subtotal deferred tax assets	(1,036,957)	(1,135,803)
Total net deferred tax liabilities	$ 1,080,772	$ 1,141,581

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. Net operating losses generated in 2018 and thereafter have no expiration date. No valuation allowance has been provided for net operating loss carryforwards.

As of December 31, 2023, and 2022, 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 2020 through 2023. 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 each of Colstrip Units 3 and 4, which are coal-fired generating units located in Colstrip, Montana. PSE has accelerated the depreciation of Colstrip Units 3 and 4 to December 31, 2025 as part of the 2019 GRC. The 2017 GRC repurposed PTCs and hydro-related treasury grants to recover unrecovered plant costs and to fund and recover decommissioning and remediation costs for Colstrip Units 1 through 4. Additional costs beyond those covered by PTCs and hydro-related treasury grants are being recovered through a separate Colstrip tariff as part of the 2022 GRC. In 2022, PSE and Talen Energy reached an agreement to transfer PSE's ownership interest in Colstrip Units 3 and 4 to Talen Energy on December 31, 2025. Although PSE and Talen Energy signed an agreement in 2022 involving the transfer of PSE's ownership to Talen at the end of 2025, Talen emerged from a Chapter 11 bankruptcy in May 2023 without approval of the agreement, so the parties have agreed to continue discussions about the status of PSE's ownership stake. Management evaluated Colstrip Units 3 and 4 and determined that the applicable held for

sale and abandonment accounting criteria were not met as of December 31, 2023. As such, Colstrip Units 3 and 4 are classified as Electric Utility Plant on the Company's balance sheet as of December 31, 2023.

Consistent with a June 2019 announcement, Talen permanently shut down Units 1 and 2 at the end of 2019 due to operational losses associated with the Units. Colstrip Units 1 and 2 were retired effective December 31, 2019. The Washington Clean Energy Transformation Act requires the Washington Commission to provide recovery of the investment, decommissioning, and remediation costs associated with the facilities that are not recovered through the repurposed PTCs and hydro-related treasury grants. The full scope of decommissioning activities and costs may vary from the estimates that are available at this time.

In May 2021, PSE along with the Colstrip owners, Avista Corporation, PacifiCorp and Portland General Electric Company, filed a lawsuit against the Montana Attorney General challenging the constitutionality of Montana Senate Bill 266. On September 28, 2022, the magistrate judge in the District Court proceeding issued a recommendation to the presiding U.S. District Court Judge that a permanent injunction against enforcement of Senate Bill 266 be granted. In October 2022, the U.S. District Court Judge accepted in full the magistrate judge's recommendation for a permanent injunction against enforcement of Senate Bill 266. The Court entered judgment and a permanent injunction in favor of PSE and the Colstrip owners on November 15, 2022. No party filed a notice of appeal.

Puget LNG

In January 2018, the Puget Sound Clean Air Agency (PSCAA) determined a Supplemental Environmental Impact Statement (SEIS) was necessary in order to rule on the air quality permit for the facility. In December 2019, PSCAA issued the air quality permit for the facility, a decision which was appealed to the Washington Pollution Control Hearings Board (PCHB) by each of the Puyallup Tribe of Indians and nonprofit law firm Earthjustice. In November 2021, the PCHB affirmed the PSCAA ruling in PSE's favor. In December 2021, the PCHB decision was appealed with the Pierce County Superior Court by each of the Puyallup Tribe of Indians and nonprofit law firm Earthjustice. The appeal did not delay commissioning or commercial operations at the plant, which commenced on February 1, 2022. On February 4, 2022, the court transferred the appeal to the Washington Court of Appeals Division II (Wash. Ct. App. Div. II) for direct review. On December 26, 2023 the Wash. Ct. App. Div. II affirmed the PCHB decision on all counts. The State of Washington Division II Court of Appeals upheld the permit issuance and in February 2024 denied the Puyallup Tribe of Indians' motion to reconsider. On March 22, 2024, a coalition of environmental organizations lead by Advocates for a Cleaner Tacoma, petitioned the Washington Supreme Court to review portions of the Court of Appeals' decision. On March 25, 2024, the Puyallup Tribe of Indians also petitioned the Washington Supreme Court for review.

(15) Commitments and Contingencies

For the year ended December 31, 2023, approximately 11.1% of the Company's energy output was obtained at an average cost of approximately $0.053 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)	2023	2022
PUD contract costs	$ 174,385	$ 149,575

As of December 31, 2023, the Company purchased portions of the power output of the PUDs' projects as set forth in the following table:

		Company's Share of					
(Dollars in Thousands)	Contract Expiration	2024 Percent of Output	2024 Megawatt Capacity	Estimated 2024 Total Costs	2024 Debt Service Costs	Interest included in 2024 Debt Service Costs	Debt Outstanding
Chelan County PUD[1]:							
Rock Island Project	2051	35.0 %	220	$ 68,410	$ 17,645	$ 4,059	$ 105,617
Rocky Reach Project	2051	35.0	472	84,453	6,838	2,015	35,555
Douglas County PUD[2]:							
Wells Project	2029	17.3	145	28,310	—	—	—
Grant County PUD[3]:							
Priest Rapids Development	2052	4.8	46	28,781	329	176	4,061
Wanapum Development	2052	4.8	95	28,781	329	176	4,061
Total			978	$ 238,735	$ 25,141	$ 6,426	$ 149,294

1. *PSE currently purchases output from Chelan County PUD's Rock Island and Rocky Reach hydroelectric projects under three separate contracts: 1) a contract for 25% of output that was executed in February 2006 and expires October 31, 2031. In 2023, PSE executed a new contract extending this 25% share of output through October 2051; 2) a contract executed in March 2021 for 5% of output that began on January 1, 2022 and continues through December 31, 2026; and 3) a contract executed during 2023 to purchase an additional 5% of output for each from January 1, 2024 through December 31, 2028.*
2. *PSE currently purchases output from Douglas County PUD's Wells hydroelectric project under two separate contracts: 1) a contract executed in March 2017 with a variable share output (average 11.82% in 2024) that began on September 1, 2018 and ends September 30, 2028; and 2) a contract executed in March 2021 for 5.5% of output from October 1, 2021 through September 30, 2024. In 2023, PSE executed a new contract extending this 5.5% share of output through September 30, 2029.*
3. *PSE currently purchases output from Grant County PUD's Wanapum and Priest Rapids hydroelectric developments under two separate contracts: 1) a contract that was executed on December 13, 2001 and began November 1, 2005 under which PSE receives 0.64% of output through expires March 31, 2052; and 2) a contract entered in November 2023 for 4.18% of output that begins on January 1, 2024, and continues through December 31, 2024. PSE reserves the right to renew the latter contract on an annual basis.*

The following table summarizes the Company's estimated payment obligations for power purchases from the Columbia River projects, electric portfolio contracts and electric wholesale market transactions. These contracts have varying terms and may include escalation and termination provisions.

(Dollars in Thousands)	2024	2025	2026	2027	2028	Thereafter	Total
Columbia River projects	$ 226,616	$ 196,843	$ 196,722	$ 179,740	$ 180,995	$ 3,431,358	$ 4,412,274
Electric portfolio contracts	459,999	416,634	192,381	184,277	175,788	2,044,137	3,473,216
Electric wholesale market transactions	202,692	55,432	12,125	—	—	—	270,249
Total	$ 889,307	$ 668,909	$ 401,228	$ 364,017	$ 356,783	$ 5,475,495	$ 8,155,739

Total purchased power contracts provided the Company with approximately 14.7 million and 15.3 million MWhs of firm energy at a cost of approximately $851.6 million and $892.7 million for the years 2023 and 2022, 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 21 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage.

The Company incurred demand charges of $137.6 million and $138.3 million for firm transportation, storage and peaking services for its natural gas customers for the years 2023 and 2022. The Company incurred demand charges of $60.5 million and $53.9 million for firm transportation, storage and peaking services for the natural gas supply for its combustion turbines for the years 2023 and 2022.

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 Canadian Energy Regulator (CER) currently authorized rates, which are subject to change.

Natural Gas Supply and Demand Charge Obligations (Dollars in Thousands)	2024	2025	2026	2027	2028	Thereafter	Total
Natural gas wholesale market transactions	$ 535,134	$ 466,669	$ 327,471	$ 190,303	$ 96,129	$ —	$ 1,615,706
Firm transportation service	182,771	163,644	161,471	163,028	159,435	818,802	1,649,151
Firm storage service	9,356	9,350	8,476	8,189	2,678	5,783	43,832
Total	$ 727,261	$ 639,663	$ 497,418	$ 361,520	$ 258,242	$ 824,585	$ 3,308,689

Service Contracts

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

Service Contract Obligations (Dollars in Thousands)	2024	2025	2026	2027	2028	Thereafter	Total
Energy production service contracts	$34,702	$35,391	$36,113	$36,848	$37,621	$96,826	$277,501

Legal Matters

Washington Climate Commitment Act

In 2021, the Washington Legislature adopted the CCA, which establishes a GHG emissions cap-and-invest program that requires covered entities, including electric and natural gas utilities, to purchase allowances to cover their GHG emissions with a cap on available allowances beginning on January 1, 2023 that declines annually through 2050. WDOE published final regulations to implement the program on September 29, 2022, which became effective on October 30, 2022. WDOE also indicated that there will be subsequent rulemakings building off initial rulemaking as program implementation proceeds and Washington carbon goals is evaluated.

One component of the CCA rules stipulates that GHG emissions associated with exported electricity are covered emissions and require an allowance offset to the extent these exports are not sourced from a non-emitting resource. Another component of the CCA rules stipulates GHG emissions associated with imported electricity are covered emissions and require an allowance offset for the first jurisdictional deliverer serving as the electricity importer for that electricity. Per RCW 70A.65.010(42)(d), imported electricity does not include electricity imports of unspecified electricity that are netted by exports of unspecified electricity to any jurisdiction not covered by a linked program by the same entity within the same hour. Under this definition, hourly power transmission data is required to determine PSE's net imported electricity compliance

obligation. Although the Company is actively engaged in determining the hourly net generation, imports and exports, the methodology for netting these components by hour that will be required by the WDOE to calculate the compliance obligation is uncertain, and PSE expects further rulemaking and agency interpretations to clarify this uncertainty in future periods. Due to the estimation uncertainty as of the date of this disclosure, the company considered a range of outcomes depending on the proportion of exported electricity that is sourced from non-emitting resources and whether all unspecified electricity imports and exports fully net on an hourly basis, none net, or a portion do. As of December 31, 2023, the Company's estimated the range of possible outcomes to be between $95.9 and $280.2 million depending on the methodology applied in netting unspecified electricity imports and exports. Since no amount in the range represents a better estimate than any other amount, the Company accrued to the minimum amount in the range. As existing uncertainties are resolved in future periods, any change in compliance costs as a result of such estimated additional liabilities would be deferred under ASC 980 as a regulatory asset consistent with Docket No. UE-220974, as these amounts may be recoverable from customers in future utility rates.

Other Commitments and Contingencies

For information regarding PSE's environmental remediation obligations, see Note 3, "Regulation and Rates".

(16) Accumulated Other Comprehensive Income (Loss)

The following tables present the changes in the Company's (loss) AOCI by component for the years ended December 31, 2023 and 2022, 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 treasury interest rate swaps	Total
Balance at December 31, 2021	$ (108,541)	$ (4,600)	$ (113,141)
Other comprehensive income (loss) before reclassifications	(4,512)	—	(4,512)
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	14,223	386	14,609
Net current-period other comprehensive income (loss)	9,711	386	10,097
Balance at December 31, 2022	$ (98,830)	$ (4,214)	$ (103,044)
Other comprehensive income (loss) before reclassifications	44,277	—	44,277
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	(12)	385	373
Net current-period other comprehensive income (loss)	44,265	385	44,650
Balance at December 31, 2023	$ (54,565)	$ (3,829)	$ (58,394)

Details about the reclassifications out of AOCI (loss) for the years ended December 31, 2023 and 2022, 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) 2023	2022
Net unrealized gain (loss) and prior service cost on pension plans:			
Amortization of prior service cost	(a)	$ (172)	$ (311)
Amortization of net gain (loss)	(a)	187	(17,693)
	Total before tax	$ 15	$ (18,004)
	Tax (expense) or benefit	(3)	3,781
	Net of tax	$ 12	$ (14,223)
Net unrealized gain (loss) on treasury interest rate swaps:			
Interest rate contracts	Interest expense	(488)	(488)
	Tax (expense) or benefit	103	102
	Net of Tax	$ (385)	$ (386)
Total reclassification for the period	Net of Tax	$ (373)	$ (14,609)

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[a] These AOCI components are included in the computation of net periodic pension cost, see Note 12, "Retirement Benefits" for additional details.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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)	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 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year		(108,555,551)			(4,582,997)		(113,138,548)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income		14,223,604			385,239		14,608,843		
3	Preceding Quarter/Year to Date Changes in Fair Value		(4,515,325)					(4,515,325)		
4	Total (lines 2 and 3)		9,708,279			385,239		10,093,518	490,950,387	501,043,905
5	Balance of Account 219 at End of Preceding Quarter/Year		(98,847,272)			(4,197,758)		(103,045,030)		
6	Balance of Account 219 at Beginning of Current Year		(98,847,272)			(4,197,758)		(103,045,030)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income		(11,376)			385,239		373,863		
8	Current Quarter/Year to Date Changes in Fair Value		44,274,859					44,274,859		
9	Total (lines 7 and 8)		44,263,483			385,239		44,648,722	131,059,170	175,707,892
10	Balance of Account 219 at End of Current Quarter/Year		(54,583,789)			(3,812,519)		(58,396,308)		

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	16,913,856,243	10,869,139,274	5,176,955,011				867,761,958
4	Property Under Capital Leases	289,435,404	39,358,368					250,077,036
5	Plant Purchased or Sold							
6	Completed Construction not Classified	1,032,004,041	742,689,871	184,341,112				104,973,058
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	18,235,295,688	11,651,187,513	5,361,296,123				1,222,812,052
9	Leased to Others							
10	Held for Future Use	59,561,465	49,315,001	10,246,464				
11	Construction Work in Progress	1,156,264,737	1,060,266,765	100,170,208				(4,172,236)
12	Acquisition Adjustments	282,791,675	282,791,675					
13	Total Utility Plant (8 thru 12)	19,733,913,565	13,043,560,954	5,471,712,795				1,218,639,816
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	7,763,962,154	5,319,116,637	2,044,580,958				400,264,559
15	Net Utility Plant (13 less 14)	11,969,951,411	7,724,444,317	3,427,131,837				818,375,257
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	7,253,904,526	5,092,947,633	2,029,432,815				131,524,078
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	332,837,377	48,948,753	15,148,143				268,740,481
22	Total in Service (18 thru 21)	7,586,741,903	5,141,896,386	2,044,580,958				400,264,559
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	Amortization of Plant Acquisition Adjustment	177,057,826	177,057,826					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	7,763,962,154	5,319,116,637	2,044,580,958				400,264,559

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
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: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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 the 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) 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.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization	114,202					114,202
3	(302) Franchise and Consents	79,706,707	501,373	11,430			80,196,650
4	(303) Miscellaneous Intangible Plant	120,636,783	11,723,207	56,829,721			75,530,269
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	200,457,692	12,224,580	56,841,151			155,841,121
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	2,788,745					2,788,745
9	(311) Structures and Improvements	136,208,233	121,204				136,329,437
10	(312) Boiler Plant Equipment	522,963,324	2,079,486	1,196,665			523,846,145
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	281,739,623	1,698,525	2,823,454			280,614,694
13	(315) Accessory Electric Equipment	38,963,991	648,177	315,099			39,297,069
14	(316) Misc. Power Plant Equipment	7,581,106	346,142	252,660			7,674,588
15	(317) Asset Retirement Costs for Steam Production	43,758,248					43,758,248
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,034,003,270	4,893,534	4,587,878			1,034,308,926
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	11,306,992					11,306,992
28	(331) Structures and Improvements	179,267,298	153,075				179,420,373
29	(332) Reservoirs, Dams, and Waterways	365,477,625	16,293,032	450,251			381,320,406
30	(333) Water Wheels, Turbines, and Generators	139,713,005	4,964	131,474			139,586,495
31	(334) Accessory Electric Equipment	55,490,459	3,698				55,494,157
32	(335) Misc. Power Plant Equipment	16,685,325	100,758	17,806			16,768,277
33	(336) Roads, Railroads, and Bridges	5,045,062					5,045,062
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	772,985,766	16,555,527	599,531			788,941,762
36	D. Other Production Plant						
37	(340) Land and Land Rights	16,016,762					16,016,762
38	(341) Structures and Improvements	133,513,921	1,262,966	1,016,598			133,760,289
39	(342) Fuel Holders, Products, and Accessories	26,274,619	629,285				26,903,904

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
40	(343) Prime Movers						
41	(344) Generators	1,636,397,887	81,715,842	51,783,146			1,666,330,583
42	(345) Accessory Electric Equipment	156,968,221	4,105,083	1,643,310			159,429,994
43	(346) Misc. Power Plant Equipment	21,558,270	1,558,432				23,116,702
44	(347) Asset Retirement Costs for Other Production	53,575,909					53,575,909
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,044,305,589	89,271,608	54,443,054			2,079,134,143
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,851,294,625	110,720,669	59,630,463			3,902,384,831
47	3. Transmission Plant						
48	(350) Land and Land Rights	64,355,939	119				64,356,058
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	11,878,174	6,887				11,885,061
50	(353) Station Equipment	711,730,921	74,633,516	1,961,272			784,403,165
51	(354) Towers and Fixtures	92,279,886	14,251	32,971			92,261,166
52	(355) Poles and Fixtures	440,701,872	147,499,243	2,655,102			585,546,013
53	(356) Overhead Conductors and Devices	337,038,615	74,360,235	102,556			411,296,294
54	(357) Underground Conduit	1,210,859					1,210,859
55	(358) Underground Conductors and Devices	36,956,731					36,956,731
56	(359) Roads and Trails	2,494,713					2,494,713
57	(359.1) Asset Retirement Costs for Transmission Plant	3,234,300	(1,263,122)				1,971,178
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,701,882,010	295,251,129	4,751,901			1,992,381,238
59	4. Distribution Plant						
60	(360) Land and Land Rights	46,599,255	1,589,632			(21)	48,188,866
61	(361) Structures and Improvements	8,254,721					8,254,721
62	(362) Station Equipment	525,180,724	23,202,458	3,364,148			545,019,034
63	(363) Energy Storage Equipment – Distribution	1,210,115					1,210,115
64	(364) Poles, Towers, and Fixtures	509,747,449	38,252,048	2,906,635			545,092,862
65	(365) Overhead Conductors and Devices	650,144,028	64,050,884	6,060,859			708,134,053
66	(366) Underground Conduit	881,223,861	60,879,526	1,231,013			940,872,374
67	(367) Underground Conductors and Devices	1,220,390,532	93,069,526	6,582,707			1,306,877,351
68	(368) Line Transformers	595,580,939	42,250,411	4,728,365	(99,142)		633,003,843
69	(369) Services	204,371,296	6,219,202	384,834			210,205,664
70	(370) Meters	268,159,457	50,509,362	55,756,826	(31,047)		262,880,946
71	(371) Installations on Customer Premises	854,792					854,792
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	64,924,902	2,654,130	5,827			67,573,205
74	(374) Asset Retirement Costs for Distribution Plant	10,622,685	(4,867,769)				5,754,916
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,987,264,756	377,809,410	81,021,214	(130,189)	(21)	5,283,922,742
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	5,100,521					5,100,521
87	(390) Structures and Improvements	113,151,052	13,570,118				126,721,170
88	(391) Office Furniture and Equipment	31,186,920	6,673,684	6,262,907			31,597,697
89	(392) Transportation Equipment	2,182,246	1,866,850	55,031			3,994,065
90	(393) Stores Equipment	170,597	1,798,594				1,969,191
91	(394) Tools, Shop and Garage Equipment	26,306,435	6,087,765	22,018			32,372,182
92	(395) Laboratory Equipment	6,654,825		681,203			5,973,622

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
93	(396) Power Operated Equipment	5,519,575	(863,009)	1,941,053			2,715,513
94	(397) Communication Equipment	102,753,341	7,685,517	4,606,811			105,832,047
95	(398) Miscellaneous Equipment	402,560		20,985			381,575
96	SUBTOTAL (Enter Total of lines 86 thru 95)	293,428,072	36,819,519	13,590,008			316,657,583
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)	293,428,072	36,819,519	13,590,008			316,657,583
100	TOTAL (Accounts 101 and 106)	11,034,327,155	832,825,307	215,834,737	(130,189)	(21)	11,651,187,515
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)	11,034,327,155	832,825,307	215,834,737	(130,189)	(21)	11,651,187,515
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ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
2						
3						
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44						
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46						
47	TOTAL					

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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	03/30/2009	10/15/2029	751,377
3	DISTRIBUTION E3600 - BAINBRIDGE SUBSTATION LAND	02/28/2009	01/01/2035	618,393
4	DISTRIBUTION E3600 - BEL-RED SUBSTATION LAND	12/31/2009	01/01/2035	2,184,109
5	DISTRIBUTION E3600 - BETHEL SUBSTATION LAND	12/31/2005	01/01/2035	710,313
6	DISTRIBUTION E3600 - BUCKLEY SUBSTATION LAND	01/05/2009	03/29/2024	488,523
7	DISTRIBUTION E3600 - CARPENTER SUBSTATION LAND	04/28/2009	12/31/2027	1,041,420
8	DISTRIBUTION E3890 - CLYDE HILL SUBSTATION LAND	10/01/2014	01/01/2035	397,742
9	DISTRIBUTION E3600 - JENKINS CREEK SUBSTATION LAND	10/30/2009	01/01/2033	1,000,291
10	DISTRIBUTION E3600 - KENDALL SUBSTATION LAND	01/31/2010	01/01/2031	353,720
11	DISTRIBUTION E3600 - LAKE HOLMS SUBSTATION LAND	01/01/2012	01/01/2033	912,413
12	DISTRIBUTION E3600 - MITIGATION LAND GOPHER	12/31/2018	03/22/2024	2,490,934
13	DISTRIBUTION E3600 - PLUM STREET SUBSTATION LAND	02/28/2014	01/01/2035	305,609
14	TRANSMISSION E3500 - BPA KITSAP NAVAL TRANS PLANT	12/31/1992	01/01/2035	436,566
15	TRANSMISSION E3501 -BPA KITSAP NAVAL YARD TRANS	01/21/2016	01/01/2035	460,720
16	TRANSMISSION E3500 -HAZELWOOD SUBSTATION - LAND	01/31/2014	01/01/2035	460,994
17	TRANSMISSION E3500 -HOFFMAN SWITCHING STATION DISTR	03/31/2005	01/01/2035	714,663
18	TRANSMISSION E3557 / E3567 -SAINT CLAIR - PLEASANT	01/31/2014	01/01/2035	1,870,639
19	TRANSMISSION E3507 -SO. BREMERTON-BANGOR LAND	09/04/2007	01/01/2035	1,005,331
20				
21				
22				
23				
21	Other Property:			
22	OTHER PROPERTY (less than $250,000)			516,707
23	Land and Rights: (continued)			
24	INTANGIBLE E303 - LOWER SNAKE RIVER WIND	03/31/2014	01/01/2028	22,243,546
25	INTANGIBLE E303 - BEAVER CREEK WIND	12/31/2023	12/31/2027	10,350,991
47	TOTAL			49,315,001

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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	ADMS-Distribution Management System	21,913,339
2	Bainbridge Island Transmission Project	24,875,200
3	Baker Project	263,460,483
4	Beaver Creek Project	262,163,012
5	Berrydale-Krain Transmission Line Project	1,625,863
6	Bremerton-Bangor Project	1,457,762
7	Buckley Project	14,531,791
8	Cascade - White River Project	1,729,552
9	Commercial Line Extension	1,179,630
10	Cystal Mountain Project	2,885,948
11	Electron Heights Project	1,016,909
12	Energize Eastside Transmission Project	114,408,972
13	Energy Management System	2,235,955
14	Ferndale Project	1,415,255
15	Fredonia Project	5,013,371
16	Greenwater Tap Project	3,738,584
17	King County CZ Program	2,250,945
18	Lynden Project	3,171,940
19	Multi Family Line Extension	1,081,699
20	OH Sys Rel Upgrades	6,904,166
21	OH Sys Rel Upgrades Tree Wire	3,789,839
22	OH UG Rel PI Driven	3,299,490
23	Phantom Lake - Lake Hills Project	12,583,342
24	Pole Replacement Project	10,760,170
25	Sammamish - Juanita Project	6,555,249
26	Sammamish Improvement Project	3,502,778
27	Seabeck Reliability Project	1,102,363
28	Sedro-Bellingham Project	7,034,348
29	Smart Grid Project	2,626,294
30	Substation Reliability Project	10,720,896
31	Whitehorn Project	3,963,916
32	Woodland - St Clair Project	3,261,292
33	WSDOT	2,413,676
34	CWIP less than $1,000,000 each - Electric Distribution	188,572,147
35	CWIP less than $1,000,000 each - Electric Transmission	37,743,643
36	CWIP less than $1,000,000 each - Electric General Plant & Intangibles	19,981,942
37	CWIP less than $1,000,000 each - Electric Generation	5,295,004
43	Total	1,060,266,765

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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 12, column (c), and that reported for electric plant in service, page 204, column (d), 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.

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)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	4,902,238,564	4,902,076,139	162,425	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	393,750,409	393,750,409		
4	(403.1) Depreciation Expense for Asset Retirement Costs	3,764,421	3,764,421		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):				
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	397,514,830	397,514,830		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(180,595,572)	(180,595,572)		
13	Cost of Removal	(29,309,371)	(29,309,371)		
14	Salvage (Credit)	3,099,608	3,099,608		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(206,805,335)	(206,805,335)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	(1,754,755)	[a](1,754,755)		
17.2	Transferr & Impairment Gain/Loss	88,275,464	88,275,464		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	5,179,468,768	5,179,306,343	162,425	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	953,504,602	953,504,602		
21	Nuclear Production				
22	Hydraulic Production-Conventional	270,525,277	270,525,277		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,084,449,271	1,084,449,271		
25	Transmission	663,570,457	663,408,032	162,425	
26	Distribution	2,008,273,620	2,008,273,620		
27	Regional Transmission and Market Operation				
28	General	199,145,541	199,145,541		
29	TOTAL (Enter Total of lines 20 thru 28)	5,179,468,768	5,179,306,343	162,425	

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FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToAccumulatedDepreciation

The 2017 General Rate Case on Dockets UE-170033 and UG-170034, approved by the WUTC, instructed the company to repurpose Federal hydro grants and production tax credits (“PTCs”) to offset certain Colstrip costs (unrecovered plant, decommissioning and remediation cost and Colstrip transition fund) and to move the balances to 108 FERC accounts. This balance represents the use of the repurposed PTCs and hydro grants to offset incurred costs related to Colstrip. In addition, Other debit and credit items includes manual adjustments to comply with the referenced docket.

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder 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.
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 from investments, including such revenues from 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 different 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.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	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)
1	Common			10,200			10,200	
2	Retained Earnings			(13,264,970)	210,368		(13,054,602)	
3	Additional Paid in Capital			51,837,244			51,837,244	
4	Subtotal			38,582,474	210,368		38,792,842	
42	Total Cost of Account 123.1 $ 38,792,842.00		Total	38,582,474	210,368		38,792,842	0

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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)	21,182,653	32,347,791	
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)	110,142,293	150,218,316	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	7,620,965	8,536,774	Electric & Gas
8	Transmission Plant (Estimated)	709,535	773,700	Electric & Gas
9	Distribution Plant (Estimated)	11,260,489	12,754,847	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,550,618	[a]1,575,390	Electric & Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	131,283,900	173,859,027	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	221,957		Electric & Gas
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	156,825	(1,312,553)	Electric & Gas
17				
18				
19				
20	TOTAL Materials and Supplies	152,845,335	204,894,265	

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FOOTNOTE DATA

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

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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.
6. Report on Line 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 acquired 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 and 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.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	106,378	731,067	9,030		9,033		9,030		234,919		368,390	731,067
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9	Purchased: California Carbon Allowances	10,000	373,000									10,000	373,000
10	[a] Purchased: WA Carbon Allowances - Elec	20,561	1,067,116									20,561	1,067,116
11	Purchased: WA Carbon Allowances - Gas	2,257,180	128,128,132									2,257,180	128,128,132
12	Transfer: Talen MT	(1,236)								5,326		4,090	
13	Initial Allocation to PSE (WCA-Electric)	6,642,604		6,003,582						3,686		12,649,872	
14	Initial Allocation to PSE (WCA-Gas)	4,906,163		4,536,882								9,443,045	
15	Total	13,835,272	129,568,248	10,540,464						9,012		24,384,748	129,568,248
16													
17	Relinquished During Year:												
18	Charges to Account 509	26										26	
19	Other:												
20	Allowances Used												
20.1	California Carbon Allowances	7,413	207,134									7,413	207,134
20.2	[b] Washington Carbon Allowances	11,215,597	128,257,798	2,155,019								13,370,616	128,257,798
21	Cost of Sales/Transfers:												
22	[c] WA Compliance Liability (Electric)	(1,822,705)	(94,874,884)									(1,822,705)	(94,874,884)
23	[d] WA Compliance Liability (Gas)	(1,441,983)	(74,941,539)									(1,441,983)	(74,941,539)
24													
25													
26													
27													
28	Total	(3,264,688)	(169,816,423)									(3,264,688)	(169,816,423)
29	Balance-End of Year	(546,074)	(167,982,040)	8,394,475		9,033		9,030		243,931		8,110,395	(167,982,040)
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	[e] 3,648										3,648	
37	Add: Withheld by EPA												

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
38	Deduct: Returned by EPA	191										191	
39	Cost of Sales												
40	Balance-End of Year	3,457										3,457	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)		[(f)]6										6
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												
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FOOTNOTE DATA

(a) Concept: AllowancesInventoryPurchasesTransfersDescription

Washington Carbon Allowances for electric price containment reserve purchased at auction. No vintage assigned, so treated as the same vintage as the year acquired.

(b) Concept: AllowancesRelinquishedOtherDescription

	2023 Electric WA Carbon Allowances Retired	2023 Gas WA Carbon Allowances Retired	2023 Gas WA Carbon Allowances Sold*	Total
Quantity	4,070,254	3,956,337	3,189,006	11,215,597
Amount	$1,067,116	$127,190,682	$—	$128,257,798

* Free allowances consigned for sale.

	2024 Electric WA Carbon Allowances Retired	2024 Gas WA Carbon Allowances Retired*	2024 Gas WA Carbon Allowances Sold*	Total
Quantity	—	1,361,064	793,955	2,155,019
Amount	$—	$—	$—	$—

* Free allowances retired or consigned for sale.

(c) Concept: AllowancesInventoryCostOfSalesTransfersDescription

The provisions for Washington's Climate Commitment Act became applicable effective January 1, 2023. This line represents the estimated carbon liability for PSE's electric business as of December 31, 2023.

(d) Concept: AllowancesInventoryCostOfSalesTransfersDescription

The provisions for Washington's Climate Commitment Act became applicable effective January 1, 2023. This line represents the estimated carbon liability for PSE's natural gas business as of December 31, 2023.

(e) Concept: AllowancesWithheldNumber

The following table reflects 2023 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	12/31/22 Estimated Balance of Withheld Allowances Years 2009-2025	Estimated EPA Withheld Allowances Sold During 2023	12/31/23 Estimated Balance of Withheld Allowances Year 2009-2025
Colstrip Unit 1	666	78	588
Colstrip Unit 2	644	78	566
Colstrip Unit 3	584	20	564
Colstrip Unit 4	1,754	15	1,739
	3,648	191	3,457

(f) Concept: AllowancesWithheldNetSalesProceedsFromAllowanceSalesAssociatedCompany

2023 proceeds from sales of allowances withheld by the Environmental Protection Agency were as follows:

Plant	2023 Proceeds
Colstrip Unit 1	$ 2.35
Colstrip Unit 2	2.34
Colstrip Unit 3	0.59
Colstrip Unit 4	0.46
Total Proceeds	$ 5.74

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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.
6. Report on Line 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 acquired 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 and 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.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
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	Allowances Used												
20.1	Allowances Used												
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												

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												
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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 Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	[(a)] 2017 Storm Excess Costs			407	12,707,858	
2	2017 Storm Recovery			407	147,517	
3	2018 Storm Excess Costs			407	8,991,057	3,256,213
4	2019 Storm Excess Costs					28,513,473
5	[(b)] 2020 Storm Excess Costs			407	11,400,537	
6	2021 Storm Excess Costs			407	3,547,538	37,529,267
7	2022 Storm Excess Costs		2,141,432			23,572,148
8	2021 Storm Recovery for next MYRP		2,882,709			2,882,709
20	TOTAL		5,024,141		36,794,507	95,753,810

FOOTNOTE DATA

(a) Concept: DescriptionOfExtraordinaryPropertyLoss

The final orders for the 2019 GRC modified the 4-year and 6-year amortization periods, previously approved for storms approved under UE-170033, to a 5-year amortization period. Therefore, all approved storm deferral accounts should be amortized over 5 years using the monthly amounts approved in the rate case which were based on estimated June 2020 balances. Based on the authorized annual amortization of $21,846,431, the monthly entry will be $1,820,536. The monthly entry started on October 15, 2020 with 2012 storm deferral costs, which was the effective date of electric rates (pro-rated for October).

(b) Concept: DescriptionOfExtraordinaryPropertyLoss

The final orders for the 2022 GRC provide for total annual storm deferral amortization of $34.2 million, or $2.853 million per month. This amortization is segregated between the group of accounts originally approved for amortization over five years in PSE's 2019 GRC ($1,820,536 per month) and the group of accounts approved in UE-220066 for amortization over four years ($1,033,222 per month). The monthly entry started on January 11, 2023 with 2020 storm deferral costs, which was the effective date of electric rates (pro-rated for January).

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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 Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	[(a)] Colstrip 1&2 Unrecovered Plant	110,972,219				110,972,219
22	[(b)] Contra PTCs Monetized for Unrec P	(110,972,219)				(110,972,219)
49	TOTAL					

FOOTNOTE DATA

(a) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

Colstrip units 1&2 have been shut down with an effective date of 12/31/2019 which will be considered the retirement date. All assets related to Colstrip units 1&2 have been retired in PowerPlant, and transferred to a 182.2 account for unrecovered plant. Per the 2019 GRC order, PSE’s rates no longer include depreciation expense for Colstrip Units 1&2, therefore all depreciation related to Colstrip Units 1&2 should cease being recorded effective on the eventual rate effective date for electric (pro-rated for October).

(b) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

Colstrip units 1&2 have been shut down with an effective date of 12/31/2019 which will be considered the retirement date. All assets related to Colstrip units 1&2 have been retired in PowerPlant, and transferred to a 182.2 account for unrecovered plant. Per the 2017 GRC order, unrecovered plant is recoverable through existing balances of Production Tax Credits (PTC's). Per the 2019 GRC order, PSE’s rates no longer include depreciation expense for Colstrip Units 1&2, therefore all depreciation related to Colstrip Units 1&2 should cease being recorded effective on the eventual rate effective date for electric (pro-rated for October).

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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	BP Cherry Point Hydrogen ADDNITSLOAD System Impact Study	1,934	186064132		
3	Bufflehead BESS ADDNITSLOAD System Impact Study	756	186064988		
4	Goldeneye BESS ADDNITSLOAD System Impact Study	216	186064989		
5	Green Water BESS ADDNITSLOAD System Impact Study	351	186064990		
6	Kingfisher BESS ADDNITSLOAD System Impact Study	621	186064991		
7	BP Cherry Point Hydrogen ADDNITSLOAD Facilities Study	6,060	186065188		
8	BP Hydrogen V2 ADDNITSLOAD System Impact Study	17,857	186065690		
9	[a] See note below				
20	Total	27,795			
21	**Generation Studies**				
22	Schnebly Coulee Solar Facilities Study	2,934	186051233		
23	Wenatchee Solar Facilities Study	1,890	186053554		
24	Fresh Air Facilities Study	1,239	186054033		
25	Desert Claim 80 MW Wind Facilities Study	11,042	186055299		
26	Stony Lake Battery Facilities Study	1,211	186056891		
27	Energy Storages Resources Facility Study	2,708	186058571		
28	South Hill Facilities Study	942	186058675		
29	Logjam Battery Storage Facilities Study	1,211	186060050		
30	Spire Battery Storage Facilities Study	1,973	186060051		
31	Green Water BESS Facilities Study	4,077	186060928		
32	Bufflehead BESS Facilities Study	1,050	186061442		
33	Grebe BESS Facilities Study	4,409	186062159		
34	Goldeneye BESS Facilities Study	1,917	186062247		
35	Viero BESS Facilities Study	4,679	186062471		
36	Kingfisher BESS Facilities Study	2,080	186062553		
37	Sinclair BESS Facilities Study	269	186062677		
38	Starwood BESS Facilities Study	404	186062926		
39	Clover Creek BESS Facilities Study	600	186063201		
40	Appaloosa I Solar Facilities Study	3,321	186063202		
41	Seabrooke Simply Cycle Facilities Study	8,538	186063298		
42	Kodiak Simple Cycle Facilities Study	269	186063421		
43	Appaloosa II Solar Facilities Study	129	186063607		
44	Double R BESS System Impact Study	67	186063664		
45	Centralia BESS Facilities Study	526	186063665		
46	Spire II Energy Storage Facilities Study	331	186063746		
47	Lower Snake River Facilities Study	269	186063793		
48	Agate BESS System Impact Study	67	186063837		
49	AE Solar Facilities Study	305	186063899		
50	High Eagle System Impact Study	3,935	186064238		
51	Centralia II BESS System Impact Study	67	186064458		
52	AE Solar II Feasibility Study	113	186064523		
53	Double R BESS Facilities Study	4,335	186065086		

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
54	Agate BESS Facilities Study	17,350	186065190		
55	Centralia II BESS Facilities Study	23,019	186065312		
56	AE Solar II System Impact Study	3,523	186065313		
57	High Eagle Facilities Study	4,272	186065346		
58	Black Diamond BESS Feasibility Study	20,684	186065955		
39	Total	135,755			
40	Grand Total	163,550			
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FOOTNOTE DATA

(a) Concept: DescriptionOfStudyPerformed
Consistent with the Colstrip Transmission System - Transmission Service and Interconnection Processes and Procedures of Avista Corporation ("AVA"), NorthWestern Energy ("NWE"), PacifiCorp ("PAC"), Portland General Electric Company ("PGE") and Puget Sound Energy, Inc. ("PSE"), NorthWestern Energy the designated operator conducts studies on the Colstrip Transmission System.

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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		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	[a] Unamortized Energy Conservation Costs	10,295,889	358,721,256	182, 908	331,457,516	37,559,629
2	[b] WUTC Deferred AFUDC	61,463,089	260,686	406	3,075,450	58,648,325
3	[c] Colstrip 1&2 Western Energy Coal Reserve - 10 years	128,755,044	6,300,469	186, 406	4,635,914	130,419,599
4	[d] Colstrip Deferred Depreciation - 17.5 years	206,017	25,982,786	406, 407,408	195,552	25,993,251
5	[e] Environmental Remediation Costs	14,868,879	11,114,905	Various	12,434,426	13,549,358
6	[f] Property Tax Tracker	12,397,881	23,490,893	182, 283, 408	47,023,920	(11,135,146)
7	[g] Decoupling Mechanism	36,773,072	90,099,488	Various	95,474,745	31,397,815
8	[h] Low Income Home Energy Assistance Program	17,370,482	48,280,148	182, 253, 908	66,597,988	(947,358)
9	[i] Power Cost Adjustment Mechanism	112,207,122	188,718,001	182, 419, 557	252,498,884	48,426,239
10	[j] White River Regulatory Assets - 3 years	3,780	645	182		4,425
11	[k] Chelan PUD - 20 years	62,611,246		555	7,088,066	55,523,180
12	[l] Mint Farm Deferral - 15 years	6,325,127		407	2,885,052	3,440,075
13	[m] Lower Snake River Deferral - 25 years	52,501,201	1	253, 407	5,592,477	46,908,725
14	[n] WUTC AMI, EV & GTZ Deferral	39,753,332	51,678,927	407	43,721,437	47,710,822
15	[o] PLR EDIT	(1,073,380)	2,667,081	456, 495	1,593,701	
16	[p] SPI Biomass	599,048		407	599,048	
17	[q] LNG Exp Deferral	9,981,418	17,255,452	407, 495	2,196,064	25,040,806
18	[r] Decarb/Electrification Deferral		4,072,788	182	407,503	3,665,285
19	[s] Reg Fee Deferral		561,297	419	10,753	550,544
20	[t] Sch 95A		2,756,456	407	1,465,337	1,291,119
21	[u] TEP Deferral		5,884,624	407	7,806,527	(1,921,903)
22	[v] CEIP Deferral		9,611,284	182, 407	11,445,571	(1,834,287)
23	[w] Climate Commitment Act		373,696,027	Various	187,145,561	186,550,466
24	[x] Demand Response Deferral		122,345,943	Various	17,736,392	104,609,551
25	[y] U-210595 Participatory Funding Agreement		280,331	928		280,331
26	[z] Sch 129D			456, 495	6,578,555	(6,578,555)
44	TOTAL	565,039,247	1,343,779,488		1,109,666,439	799,152,296

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FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-080389, UG-080390, UE-970686 and UG-120812.
(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-130137, UG-130138, UE-072300 and UG-072301.
(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-111048 and UG-111049. Amortization of Colstrip 1&2 ReserveDedication effective until December 2019. Amortization of Colstrip 3&4 Common - AFUDC Adjustment effective through May 2024.
(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-072300 and UG-072301. Amortization effective through May 2024.
(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-991796, UE-072300, UG-072301, UE-911476, UE-021537, UE-130137, UG-130138, UE-220066, and UG-220067. Amortization effective through December 2027.
(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-111048, UG-111049, and UE -140599 effective May 2014.
(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-170033 and UG-170034.
(h) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
No docket number required.
(i) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Docket UE-011570. Total includes interest recorded on the customer balance of the PCA.
(j) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-170033 and UG-170034. New GRC 2017 for White River amortization of 3 years. Effective December 19, 2017 through December 2020. Balance forward for White River Surplus Land Sales from 2019.
(k) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-060266 and UE-060539. Amortization effective November 2011 through October 2031.
(l) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Docket UE-090704. Amortization effective April 2010 through March 2025.
(m) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-111048, UG-111049, UE-130583, UE-131099 and UE-131230. Amortization effective May 2012 through April 2037.
(n) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-180899, UG-180900, UE-190129, UE-160799, UE-180877, UE-220066 and UG-220067. Amortization effective March 2019.
(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-190529, UG-190530, UE-220066 and UG-220067 for recovery of over-funded Gas and Electric protected EDIT. Amortization effective October 2021.
(p) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Docket UE-200980. Amortization effective July 2021 through June 2023.
(q) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-220066, UG-220067 and UG-210918. Amortization effective February 2023.
(r) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-220066 and UG-220067.
(s) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-220066 and UG-220067. Amortization effective January 2023.
(t) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Docket UE-220794.
(u) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Docket UE-220066.
(v) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Docket UE-210795.
(w) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-220974 and UG-220975.
(x) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-220066 and UG-220067.
(y) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Docket UE-220196 and UG-220197
(z) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Included in Washington Commission Dockets UE-230697 and UG-230698

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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 Credits Account Charged (d)	CREDITS Credits Amount (e)	Balance at End of Year (f)
1	Incurred not Reported Worker Comp	1,460,432	360,994	186,253	837,426	984,000
2	Tacoma LNG	(90,291,293)	23,581,262	182, 253, 495	28,609,993	(95,320,024)
3	Damage Claims	5,233,355	15,902,347	186	14,366,624	6,769,078
4	Clearing Account Charges	2,285,065	2,458,095	184,186	1,741,743	3,001,417
5	FAS133 Net Unrealized		203,254,466	244	122,878,097	80,376,369
6	Chelan Prepayments - 20 Yrs	4,971,443	519,259	555	621,589	4,869,113
7	Ferndale Maintenance - 12 Yrs	6,158,924	7,312	553, 513	1,009,311	5,156,925
8	Encogen Maintenance - 10 Yrs	4,009,441		553	1,172,145	2,837,296
9	Environmental Remediation Exp	127,024,155	56,085,227	182.3, 186, 253	13,961,636	169,147,746
10	Real Estate Operating Leases - 7 Yrs	8,336,910	187,623	931	52,820	8,471,713
11	FSAS 71 - Snoqualmie License	7,444,780		253	16,519	7,428,261
12	Baker Article	6,673,732	331,411	242	775,905	6,229,238
13	SFAS 71 - Baker License	55,049,619	903,661	253	312,246	55,641,034
14	Colstrip Maintenance - 4 Yrs	5,817,925		253,513	2,010,767	3,807,158
15	AMI	35,532,260	13,395,961	182.3, 186	18,867,643	30,060,578
16	Fredonia Maintenance - 9-11 Yrs	4,020,145		553	1,074,921	2,945,224
17	Fredrickson Maintenance - 7 Yrs	962,485	708,032	513,553	696,815	973,702
18	Goldendale Maintenance - 4-8 Yrs	5,913,734	1,565	553	1,531,802	4,383,497
19	Whitehorn Maintenance - 6-12 Yrs	615,115	483,377	186	79,080	1,019,412
20	Mint Farm Maintenance - 3-7 Yrs	6,879,072		553	1,818,139	5,060,933
21	Sumas Maintenance - 11 Yrs	1,877,639	169	553	321,196	1,556,612
22	Non-Temp Facility	19,073,481	37,720,432	186, 242	26,984,690	29,809,223
23	Residential Exchange	15,785,109	147,725,041	Various	147,421,203	16,088,947
24	GTZ Depreciation	22,501,039		182	[(a)]22,501,039	
25	Minor Items	12,376,844	367,562,442	Various	366,775,276	13,164,010
26	COVID-19 Items	7,050,757	10,470,311	142, 904	424,172	17,096,896
27	Regulatory Fees	7,558,866	7,176,245	186, 407	703,604	14,031,507
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	284,321,034				395,589,865

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DecreaseInMiscellaneousDeferredExpense
Consistent with Washington Commission Dockets UE-220066 and UG-220067, Get to Zero depreciation was approved for recovery and thus in 2023 deferred balances were transferred from account 186 to 182.3 and are reported in page 232.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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 at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	SFAS 109	96,005,049	64,965,749
3	Pension and Other Compensation	33,166,144	16,718,701
4	Regulatory Assets	63,694,514	62,216,362
5	Lease	64,531,287	64,105,698
7	Other	35,239,080	36,712,632
8	TOTAL Electric (Enter Total of lines 2 thru 7)	292,636,074	244,719,142
9	Gas		
10	SFAS 109	50,702,899	48,837,899
11	Derivative Instruments	72,229,021	20,348,471
12	Pension and Other Compensation		6,256,015
15	Other	3,827,367	7,019,037
16	TOTAL Gas (Enter Total of lines 10 thru 15)	126,759,287	82,461,422
17.1	Other (Non-Operating)	10,621,084	37,838,477
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	430,016,445	365,019,041

Notes

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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.
3. Give 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 noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. 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 purpose of pledge.

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)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2		150,000,000	0.01		85,903,791	859,038				
6	Total	150,000,000			85,903,791	859,038				
7	Preferred Stock (Account 204)									
8										
9										
10										
11	Total									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-04-16	Year/Period of Report End of: 2023/ Q4

Other Paid-in Capital

1. 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 a total of all accounts for reconciliation with the balance sheet, page 112. 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 briefly explain the origin and purpose of each donation.
b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
c. Gain or 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 that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	3,064,096,691
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	100,000,000
16	Ending Balance Amount	3,164,096,691
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	3,164,096,691

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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
22	TOTAL	7,133,879

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

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

1. Report by Balance Sheet Account the 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. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. 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, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, 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) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)
1	Bonds (Account 221)										
2	First Mortgage Bonds Senior MTN 7.02% Series A		300,000,000			3,010,746		12/22/1997	12/01/2027	12/22/1997	12/01/2027
3	First Mortgage Bonds Senior MTN 7.00% Series B		100,000,000			954,608		03/09/1999	03/09/2029	03/09/1999	03/09/2029
4	5.483% Senior Notes Due 06/35		250,000,000			2,460,125		05/27/2005	06/01/2035	05/27/2005	06/01/2035
5	6.724% Senior Notes Due 06/36		250,000,000			2,527,628		06/30/2006	06/15/2036	06/30/2006	06/15/2036
6	6.274% Senior Notes Due 03/37		300,000,000			2,921,148		09/18/2006	03/15/2037	09/18/2006	03/15/2037
7	5.757% Senior Notes Due 10/39		350,000,000			3,557,361		09/11/2009	10/01/2039	09/11/2009	10/01/2039
8	5.795% Senior Notes Due 03/40		325,000,000			3,384,066		03/08/2010	03/15/2040	03/08/2010	03/15/2040
9	5.764% Senior Notes Due 07/40		250,000,000			2,587,276		06/29/2010	07/15/2040	06/29/2010	07/15/2040
10	4.434% Senior Notes Due 11/41		250,000,000			2,592,616		11/16/2011	11/15/2041	11/16/2011	11/15/2041
11	4.700% Senior Notes Due 11/51		45,000,000			511,229		11/22/2011	11/15/2051	11/22/2011	11/15/2051
12	5.638% Senior Notes Due 04/41		300,000,000			3,071,895		03/25/2011	04/15/2041	03/25/2011	04/15/2041
13	5.638% Senior Notes Due 04/41 (D)					15,000					
14	4.300% Senior Notes Due 05/45		425,000,000			3,718,750		05/26/2015	05/20/2045	05/26/2015	05/20/2045
15	4.300% Senior Notes Due 05/45 (D)					1,912,500					
16	4.223% Senior Notes Due 06/48		600,000,000			1,429,461		06/04/2018	06/15/2048	06/04/2018	06/15/2048
17	3.250% Senior Notes Due 09/49		450,000,000			6,849,000		08/30/2019	09/15/2049	08/30/2019	09/15/2049
18	3.9% Pollution Control Bonds Rev Series 2013A		138,460,000			1,473,301		05/23/2013	03/01/2031	05/23/2013	03/01/2031
19	4.0% Pollution Control Bonds Rev Series 2013B		23,400,000			248,243		05/23/2013	03/01/2031	05/23/2013	03/01/2031
20	2.893% Senior Notes Due 09/51		450,000,000					09/15/2021	09/15/2051	09/15/2021	09/15/2051
21	[(a)] Secured Medium Term Notes - 7.15% Series C		15,000,000			112,500		12/20/1995	12/19/2025	12/20/1995	12/19/2025
22	[(b)] Secured Medium Term Notes - 7.20% Series C		2,000,000			15,000		12/22/1995	12/22/2025	12/22/1995	12/22/2025
23	5.448% Senior Notes Due 06/53		400,000,000		3,500,000		12,000	05/18/2023	06/01/2053	05/18/2023	06/01/2053
24	Subtotal		5,223,860,000		3,500,000	43,352,453	12,000				
25	Reacquired Bonds (Account 222)										
26											
27											
28											
29	Subtotal										
30	Advances from Associated Companies (Account 223)										
31											
32											
33											
34	Subtotal										
35	Other Long Term Debt (Account 224)										
36											
37											
38											

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)
39	Subtotal										
33	TOTAL		5,223,860,000								

Line No.	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1		
2	300,000,000	[(c)]21,060,000
3	100,000,000	7,000,000
4	250,000,000	13,707,500
5	250,000,000	16,810,000
6	300,000,000	18,822,000
7	350,000,000	20,149,500
8	325,000,000	18,833,750
9	250,000,000	14,410,000
10	250,000,000	11,085,000
11	45,000,000	2,115,000
12	300,000,000	16,914,000
13		
14	425,000,000	18,275,000
15		
16	600,000,000	25,338,000
17	450,000,000	14,625,000
18	138,460,000	5,399,940
19	23,400,000	936,000
20	450,000,000	13,018,500
21	15,000,000	1,072,500
22	2,000,000	144,000
23	400,000,000	13,498,933
24	5,223,860,000	253,214,623
25		
26		
27		
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33	5,223,860,000	253,214,623

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription
Bonds assumed which were originally issued by Washington Natural Gas Company.
(b) Concept: ClassAndSeriesOfObligationCouponRateDescription
Bonds assumed which were originally issued by Washington Natural Gas Company.
(c) Concept: InterestExpenseBonds
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 (m).

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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)	131,059,170
2	Reconciling Items for the Year	
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	(6,659,046)
11	Others	[(a)]609,195,059
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Others	[(b)](198,040,159)
27	Federal Tax Net Income	535,555,023
28	Show Computation of Tax:	
29	Taxable Income	535,555,023
30	Tax @21%	112,466,555
31	PTC	
32	Current Federal Tax	112,466,555
33	Current State Tax	1,626,265
34	Deferred Tax	(120,751,866)
35	Total Tax	(6,659,046)

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FOOTNOTE DATA

(a) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

Line 11 Details		
Capitalized Interest		31,207,596
Decoupling Revenue		69,051,764
Plant Related		84,289,668
Non-Deductible Items		10,243,661
Other Adjustment		8,289,303
Property Tax Rate Tracker		8,975,362
Subtotal		212,057,355

(b) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Line 20 Details		
Allowance for Funds Used During Construction		(48,191,464)
Conservation Activity		(6,722,793)
Derivative Instruments		(261,177,050)
Electric and Gas Purchase Contracts		(24,724,667)
Pensions and Other Compensation		(5,547,896)
Regulatory Assets		(25,836,098)
Treasury Grant Amortization		(21,946,654)
Subtotal		(394,146,622)
Total Adjustments to Tax Expense	$	(182,089,267)

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

TAXES ACCRUED, PREPAID AND CHARGES 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 known, 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 (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) 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.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) 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 (l) through (o) how the taxes were distributed. Report in column (o) 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 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) 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.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (e)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR Taxes Accrued (Account 236) (j)	BALANCE AT END OF YEAR Prepaid Taxes (Included in Account 165) (k)
1	Municipal	Local Tax	WA	2021	22,891,305		162,740,699	163,514,431		22,117,573	
2	**Subtotal Local Tax**				22,891,305		162,740,699	163,514,431		22,117,573	
3	Other	Other Taxes	WA	2021	1,133,002		4,668,946	4,843,439		958,509	
4	**Subtotal Other Tax**				1,133,002		4,668,946	4,843,439		958,509	
5	Property	Ad Valorem Tax	WA, OR, MT	2021	64,619,774		54,217,645	68,151,319		50,686,100	
6	**Subtotal Property Tax**				64,619,774		54,217,645	68,151,319		50,686,100	
7	Income	Income Tax	Fed, CA, MT, OR	2021	(796,457)		114,092,819	118,370,171		(5,073,809)	
8	**Subtotal Income Tax**				(796,457)		114,092,819	118,370,171		(5,073,809)	
9	Excise	Excise Tax	WA	2021	28,621,012		161,616,068	160,672,685		29,564,395	
10	**Subtotal Excise Tax**				28,621,012		161,616,068	160,672,685		29,564,395	
11	Payroll	Payroll Tax	Fed, WA, OR, TX, MI	2021	4,346		32,563,727	32,565,812		2,261	
12	**Subtotal Payroll Tax**				4,346		32,563,727	32,565,812		2,261	
40	TOTAL				116,472,982		529,899,904	548,117,857		98,255,029	

Line No.	DISTRIBUTION OF TAXES CHARGED			
	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	103,454,099			59,286,600
2	103,454,099			59,286,600
3	879,365			3,789,580
4	879,365			3,789,580
5	47,092,120			7,125,525
6	47,092,120			7,125,525
7	181,201,019			(67,108,199)
8	181,201,019			(67,108,199)
9	104,687,355			56,928,713
10	104,687,355			56,928,713
11	10,966,229			21,597,499
12	10,966,229			21,597,499
40	448,280,187			81,619,718

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%									
4	7%									
5	10%									
8	TOTAL Electric (Enter Total of lines 2 thru 7)									
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL									

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

OTHER DEFERRED 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	7,299,033	Various	4,241,775	4,000,437	7,057,695
2	SFAS 106 Unfunded Liability	20,968,337	Various	9,800,622	17,126,029	28,293,744
3	Low Income Program	25,817,410	Various	57,656,268	53,312,965	21,474,107
4	Sch 85 Line Extension Cost	17,164,158	456	639,701	1,684,146	18,208,603
5	Green Power Tariff	8,602,939	456	1,809,097	2,728,378	9,522,220
6	Landlord Incentives - 5-11 Yrs	13,201,891	931	1,965,472		11,236,419
7	Workers Comp - IBNR	1,774,825	186	815,169	338,738	1,298,394
8	Residential Exchange		555	120,732,491	120,732,491	
9	Decoupling		456	925,622	925,622	
10	LSR License O&M - 25 Yrs	7,662,955	Various	8,656,097	8,173,074	7,179,932
11	Snoqualmie License O&M	7,444,780	186	16,519		7,428,261
12	Baker License Misc Def	55,049,619	186	312,246	903,661	55,641,034
13	Unearned Revenue - 11-20 Yrs	1,314,764	253, 454	4,929,786	6,475,237	2,860,215
14	Deferred Pole Contact		822	4,241,997	4,241,997	
15	PGA Unrealized Gain	287,725,009	175, 244	395,222,121	107,497,112	
16	Equity Reserve AMI	9,897,270	419	305,704	21,102,571	30,694,137
17	Unclaimed Property	451,505	131	3,394,853	3,577,421	634,073
18	Colstrip 3&4	110,437	131, 407	16,528,229	47,464,489	31,046,697
19	Mint Farm Misc Def Credit - 15 Yrs	2,007,818	419	884,724		1,123,094
20	Deferred Interchange		555	17,103,639	17,103,639	
21	Tacoma LNG	22,420,805	419, 186	14,860,752	7,954,988	15,515,041
22	Minor Items	511,452	419, 495	1,035,283	1,241,896	718,065
23	Covid-19 Help	5,011,786	186		847	5,012,633
24	Microsoft	1,752,928	143, 254	860,183	1,018,060	1,910,805
25	LT Payable - Franchise	14,450,730	131	7,620,588		6,830,142
26	Beaver Creek/Caithness		107	0	21,738,957	21,738,957
27	CEIP		419	4,150	26,388	22,238
28	BDR Fund		495, 456	1,756,602	9,884,454	8,127,852
29	2022 AMI Topside Entry	7,706,610	419	7,706,610		
47	TOTAL	518,347,061		684,026,300	459,253,597	293,574,358

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
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										

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED 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.
3. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	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)
1	Account 282										
2	Electric	790,964,113	5,173,956	55,029,159					various	23,535,649	764,644,559
3	Gas	388,752,488	9,117,517	15,630,755					various	4,262,192	386,501,442
4	Other (Specify)	(2,687,894)	200,717								(2,487,177)
5	Total (Total of lines 2 thru 4)	1,177,028,707	14,492,190	70,659,914						27,797,841	1,148,658,824
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,177,028,707	14,492,190	70,659,914						27,797,841	1,148,658,824
10	Classification of TOTAL										
11	Federal Income Tax	1,177,028,707	14,492,190	70,659,914						27,797,841	1,148,658,824
12	State Income Tax										
13	Local Income Tax										

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

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

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)	CHANGES DURING YEAR: Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR: Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits: Account Credited (g)	ADJUSTMENTS Debits: Amount (h)	ADJUSTMENTS Credits: Account Debited (i)	ADJUSTMENTS Credits: Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Pension related	47,127,225	2,769,619	8,284,853							41,611,991
4	Storm Damage	26,780,076	2,014,572	8,686,348							20,108,300
5	Regulatory Assets	72,123,585	74,945,752	73,133,440							73,935,897
6	Lease	64,627,705	3,963,467	4,316,881							64,274,291
7	Other	4,858,358	1,680,922	1,704,499							4,834,781
9	TOTAL Electric (Total of lines 3 thru 8)	215,516,949	85,374,332	96,126,021							204,765,260
10	Gas										
11	Derivative Instruments	72,229,021	47,191,934	99,072,484							20,348,471
12	Pension related	6,313,354	9,274,887	17,339							15,570,902
13	Regulatory Assets	8,971,421	45,383,122	25,953,960							28,400,583
14	Other	6,632,417		6,632,417							
17	TOTAL Gas (Total of lines 11 thru 16)	94,146,213	101,849,943	131,676,200							64,319,956
18	TOTAL Other	84,909,583			25,620,809	82,487,702					28,042,690
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	394,572,745	187,224,275	227,802,221	25,620,809	82,487,702					297,127,906
20	Classification of TOTAL										
21	Federal Income Tax										
22	State Income Tax										
23	Local Income Tax										

NOTES

Local Income Tax

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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 (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	[a] Renewable Energy Credits	(117,490)	Multiple	188,435	167,993	(137,932)
2	[b] Treasury Grants-Wind Project Expansion	(172,976)	407.4, 431	96,752	269,728	
3	[c] Decoupling Mechanisms	63,205,574	Multiple	133,635,837	131,094,646	60,664,383
4	[d] Regulatory Liability Tax Reform	800,725,088	190	54,646,183	15,542,083	761,620,988
5	[e] Green Direct Liquidated Damages	11,836,549	456	1,394,596		10,441,953
6	[f] Gain on Sale Shuffleton-Electric	(26,753)	187, 254		8,678	(18,075)
7	[g] FAS 109 EDIT Unprotected Gas & Electric	10,998,256	190, 283	11,043,573	45,317	
8	[h] Lund Hill Liquidated Damages	828,503	232			828,503
9	[i] NWP Refund for Electric	4,353,000	547	9,159,948	4,806,948	
10	[j] LNG Distribution Upgrades		495	1,301,513	3,895,452	2,593,939
11	[k] CCA Cost Recovery & Passback		Multiple	101,614,482	186,099,219	84,484,737
12	[l] Msft GRC Liability		407		407,922	407,922
41	TOTAL	891,629,751		313,081,319	342,337,986	920,886,418

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FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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.

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Shookumchuck Wind Energy Project accrual on liquidated damages. The foundation completion of 11 Turbines to be erected hascurrently been achieved as of December 16, 2019.

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Included in Washington Commission Docket UE-190606 effective August 29, 2019. On July 16, 2019, PSE filed with Washington Commission anapplication seeking a determination that 7.74 acres at its Shuffleton Switching Station Property will no longer be necessary or useful under WAC 480-143-180, and authorization for accounting treatment for the gain on sale will be recorded in FERC Account 254 (Other Regulatory Liabilities).

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

To record the unprotected FAS 109 EDIT in accordance with the 2019 GRC Order. New 254 Accounts created September 2020.

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

To record receipt of liquidated damages per Lund Hill PPA amendment #3.

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Northwest Pipeline is refunding PSE due to overcharges. PSE will pass back to customers using a split between gas and electric. New account created January 2023.

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Included in Washington Commission Docket UE-220066 and UG-220067. Amortization effective January 2023.

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

To record the cost recovery and pass back of natural gas costs and proceeds associated with the Climate Commitment Act in Gas Schedule 111.

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Included in Washington Commission Docket UE-220066 and UG-220067. Amortize regulatory liability, beginning January 2024, concurrent with rates that are charging customers for costs associated with Colstrip D&R, through the Colstrip Tracker.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

Electric Operating Revenues

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.
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 page 108, 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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	1,514,148,995	1,381,833,366	11,387,970	11,753,057	1,077,407	1,065,508
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	[a][b]1,079,565,278	988,817,103	[i]8,637,063	8,677,178	134,471	133,609
5	Large (or Ind.) (See Instr. 4)	[c][d]127,146,530	119,862,308	[j]1,070,933	1,113,909	3,202	3,238
6	(444) Public Street and Highway Lighting	20,865,111	18,414,824	69,796	69,271	9,246	8,039
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	2,741,725,914	2,508,927,601	21,165,762	21,613,415	1,224,326	1,210,394
11	(447) Sales for Resale	640,830,574	546,960,679	9,033,624	6,044,433	8	8
12	TOTAL Sales of Electricity	3,382,556,488	3,055,888,280	30,199,386	27,657,848	1,224,334	1,210,402
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	3,382,556,488	3,055,888,280	30,199,386	27,657,848	1,224,334	1,210,402
15	Other Operating Revenues						
16	(450) Forfeited Discounts	(758)	(1,092)				
17	(451) Miscellaneous Service Revenues	[e]16,254,690	[g]14,470,160				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	16,990,858	19,386,738				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[f]33,809,167	[h]52,511,725				
22	(456.1) Revenues from Transmission of Electricity of Others	34,371,414	36,229,675				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	101,425,371	122,597,206				
27	TOTAL Electric Operating Revenues	3,483,981,859	3,178,485,486				

Line12, column (b) includes $ (11,682,685) of unbilled revenues.
Line12, column (d) includes (275,827) MWH relating to unbilled revenues

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

This includes $8,171,345 of transportation revenue

(b) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $8,171,345 of electric transportation revenues classified on page 300 as (456.1), Revenues from Transmission of Electricity of Others.

(c) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

This includes $3,598,555 of transportation revenue

(d) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Includes $3,598,555 for electric transportation revenues classified on page 300 as (456.1), Revenues from Transmission of Electricity of Others.

(e) Concept: MiscellaneousServiceRevenues

Amounts Greater than $250,000 - (451) - Misc. Services Revenues		
Schedule 87 Tax Surcharge	$	9,053,556
Temporary Service Charge		1,058,985
Line Extension Revenue		1,755,863
Disconnection/Reconnection Charges		1,924,239
Non-Consumption & Consumption Misc. Service Charges		1,974,675

(f) Concept: OtherElectricRevenue

Amounts Greater than $250,000 - (456) Other Revenues		
Decoupling Revenue	$	18,986,194
Gain/(Loss) on Non-Core Gas		(47,546,521)
Schedule 129D Deferral		1,721,781
Green Energy Option Profit/Loss Deferral		943,721
Green Direct Liquidated Damages Amortization		(1,394,596)
AMI Return		(6,197,283)
Schedule 141A Deferral		2,457,874
Other Elec Revenue		(2,517,516)

(g) Concept: MiscellaneousServiceRevenues

Amounts Greater than $250,000 - (451) - Misc. Services Revenues		
Schedule 87 Tax Surcharge	$	7,460,868
Temporary Service Charge		1,114,550
Line Extension Revenue		1,884,715
Disconnection/Reconnection Charges		1,356,976
Non-Consumption & Consumption Misc. Service Charges		2,068,496
Schedule 73 Conversion		—
Wireless Application Fee Revenue		271,000

(h) Concept: OtherElectricRevenue

Amounts Greater than $250,000 - (456) Other Revenues		
Decoupling Revenues	$	(49,490,067)
Gain/(Loss) on sales or assignment of Non-core Gas		111,024,352
Green Direct Liquidated Damages Amortization		1,357,067
Green Energy Option Profit/Loss Deferral		(1,748,334)
REC Revenue		404,595
AMI Return Deferral		6,204,630
Excess Deferred Income Tax Private Letter Ruling Regulatory Asset Recognition		(16,844,165)
Other Elec Revenue		1,489,324

(i) Concept: MegawattHoursSoldSmallOrCommercial

Excludes 329,255 MWh of electric transportation volumes.

(j) Concept: MegawattHoursSoldLargeOrIndustrial

Excludes 1,941,219 MWh of electric transportation volumes.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	SCH_7E	11,554,404	1,520,537,928	1,075,598	10,742	0.1316
2	SCH_7AE	2,430	288,817	2	1,215,150	0.1188
3	SCH_307	5,507	786,051	637	8,645	0.1427
4	SCH_317	8,343	1,130,418	959	8,700	0.1355
5	SCH_327	2,374	309,976	211	11,250	0.1306
41	TOTAL Billed Residential Sales	11,573,058	1,523,053,191	1,077,407	1,254,487	0.1316
42	TOTAL Unbilled Rev. (See Instr. 6)	(185,087)	(8,904,196)			
43	TOTAL	11,387,970	1,514,148,995	1,077,407	1,254,487	0.1330

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	SCH_8E	264,766	34,730,120	31,372	8,440	0.1312
2	SCH_10E	23,042	2,449,065	12	1,920,169	0.1063
3	SCH_11E	130,050	15,537,169	312	416,827	0.1195
4	SCH_12E	16,804	1,869,372	12	1,400,333	0.1112
5	SCH_24EC	2,352,276	306,018,257	91,000	25,849	0.1301
6	SCH_25EC	2,763,441	360,860,171	7,606	363,324	0.1306
7	SCH_26EC	1,673,107	195,938,531	797	2,099,256	0.1171
8	SCH_29E	16,069	1,813,477	620	25,918	0.1129
9	SCH_31EC	891,827	100,684,932	375	2,378,206	0.1129
10	SCH_35E	4,881	407,979	2	2,440,712	0.0836
11	SCH_43E	124,085	13,993,213	143	867,725	0.1128
12	SCH_46EC	20,659	1,590,706	2	10,329,350	0.0770
13	SCH_49EC	432,410	36,232,225	14	30,886,454	0.0838
14	SCH_55E	1,959	675,948	853	2,296	0.3451
15	SCH_56E	1,662	686,846	904	1,839	0.4133
16	SCH_58E	2,022	541,325	315	6,418	0.2678
17	SCH_59E	78	24,387	36	2,165	0.3129
18	SCH_449EC		28,393	1		
19	SCH_MSOFT		8,090,728	95		
41	TOTAL Billed Small or Commercial	8,719,138	1,082,172,842	134,471	53,175,281	0.1241
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(82,075)	(2,607,564)			
43	TOTAL Small or Commercial	[a] 8,637,063	[b][c] 1,079,565,278	134,471	53,175,281	0.1250

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: MegawattHoursSoldSmallOrCommercial
Excludes 329,255 MWh of electric transportation volumes.
(b) Concept: SmallOrCommercialSalesElectricOperatingRevenue
This includes $8,171,345 of transportation revenue
(c) Concept: SmallOrCommercialSalesElectricOperatingRevenue
Includes $8,171,345 of electric transportation revenues classified on page 300 as (456.1), Revenues from Transmission of Electricity of Others.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	SCH_24EI	77,770	10,344,433	2,555	30,438	0.1330
2	SCH_25EI	141,742	19,617,690	425	333,511	0.1384
3	SCH_26EI	178,202	21,694,919	84	2,121,457	0.1217
4	SCH_31EI	507,229	57,478,151	117	4,335,287	0.1133
5	SCH_46EI	69,831	6,060,273	4	17,457,838	0.0868
6	SCH_49EI	104,176	8,594,607	3	34,725,213	0.0825
7	SCH_449EI		2,961,138	11		
8	SCH_459EI		549,068	3		
41	TOTAL Billed Large (or Ind.) Sales	1,078,950	127,300,279	3,202	59,003,744	0.1180
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(8,018)	(153,749)			
43	TOTAL Large (or Ind.)	[a] 1,070,933	[b] [c] 127,146,530	3,202	59,003,744	0.1198

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: MegawattHoursSoldLargeOrIndustrial
Excludes 1,941,219 MWh of electric transportation volumes.
(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenue
This includes $3,598,555 of transportation revenue
(c) Concept: LargeOrIndustrialSalesElectricOperatingRevenue
Includes $3,598,555 for electric transportation revenues classified on page 300 as (456.1), Revenues from Transmission of Electricity of Others.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	SCH_03E	7	864	1	7,080	0.1220
2	SCH_24EL	9,242	1,267,716	2,194	4,212	0.1372
3	SCH_25EL	926	164,572	8	115,727	0.1778
4	SCH_50E	52	8,216	10	5,234	0.1570
5	SCH_51E	3,321	1,417,749	1,433	2,317	0.4270
6	SCH_51S	70	38,982	36	1,934	0.5599
7	SCH_52E	12,465	2,512,433	2,191	5,689	0.2016
8	SCH_53E	34,807	13,854,670	3,121	11,153	0.3980
9	SCH_53S	1,630	153,248	138	11,811	0.0940
10	SCH_54E	5,538	809,784	51	108,597	0.1462
11	SCH_57E	2,208	471,551	63	35,042	0.2136
41	TOTAL Billed Public Street and Highway Lighting	70,266	20,699,787	9,246	308,796	0.2946
42	TOTAL Unbilled Rev. (See Instr. 6)	(470)	165,324			
43	TOTAL	69,796	20,865,111	9,246	308,796	0.2989

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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)
41	TOTAL Billed - All Accounts	21,441,412	2,753,226,099	1,224,326	113,742,308	
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(275,650)	(11,500,185)			
43	TOTAL - All Accounts	21,165,762	2,741,725,914	1,224,326	17,288	0.1296

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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).
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.

   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 (g) 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,line 24.
10. Footnote entries as required and provide explanations following all required data.

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)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	Port of Bremerton	RQ	Sch005	0.133	0.133	0.133	752	8,387	26,418	[b]2,610	37,415
2	Port of Brownsville	RQ	Sch005	0.203	0.203	0.203	1,343	14,030	47,207	[c]2,591	63,828
3	City of Des Moines	RQ	Sch005	0.227	0.227	0.227	1,367	14,314	48,019	[d]2,610	64,943
4	Kingston Port District	RQ	Sch005	0.121	0.121	0.121	683	7,617	23,992	[e]1,285	32,894
5	Kittitas Co PUD	RQ	Sch005	0.034	0.034	0.034	179	2,681	6,283		8,964
6	City of Oak Harbor	RQ	Sch005	0.106	0.106	0.106	626	6,703	21,986	[f]2,360	31,049
7	Poulsbo Port District	RQ	Sch005	0.076	0.076	0.076	464	4,760	16,301	[g]1,268	22,329
8	Port of Skagit - LaConner Marina	RQ	Sch005	0.078	0.078	0.078	465	4,923	16,330	[h]871	22,124
9	Port of Skagit - North Basin	RQ	Sch005	0.162	0.162	0.162	999	10,222	35,115	[i]4,876	50,213
10	Change in Unbilled Revenue	RQ	Sch005				(178)	(2,525)	(6,235)		(8,760)
11	Avangrid Renewables, LLC	AD	FERC #8				12			[j]1,350	1,350
12	Avangrid Renewables, LLC	OS	FERC #8				939,905		71,455,908		71,455,908
13	Avangrid Renewables, LLC	OS	FERC #9				27		2,110		2,110
14	Avista Corp. WWP Division	AD	FERC #8				(45)			[k](14,225)	(14,225)
15	Avista Corp. WWP Division	OS	FERC #8				22,342		1,749,777		1,749,777
16	Avista Corp. WWP Division	OS	FERC #9				39		2,651		2,651
17	Basin Electri Power	OS	FERC #8				846		64,485		64,485

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)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
18	BC Hydro	OS	FERC #9				30		2,192		2,192
19	Bonneville Power Administration	AD	FERC #8				36			[(l)]14,277	14,277
20	Bonneville Power Administration	OS	FERC #8				325,075		26,977,655		26,977,655
21	Bonneville Power Administration	OS	FERC #9				78		3,803		3,803
22	BP Energy Company	AD	FERC #8							[(m)]76	76
23	BP Energy Company	OS	FERC #8				496,878		39,504,508		39,504,508
24	Brookfield Renewable Trading and Marketing LP	AD	FERC #8							[(n)](30)	(30)
25	Brookfield Renewable Trading and Marketing LP	OS	FERC #8				125,207		8,812,873		8,812,873
26	California ISO	OS	FERC #8				883,038		52,512,832		52,512,832
27	Chelan County PUD	OS	FERC #8				16,104		837,414		837,414
28	Chelan County PUD	OS	FERC #9				16		2,033		2,033
29	Citigroup Energy Inc.	AD	FERC #8				1			[(o)]52	52
30	Citigroup Energy Inc.	OS	FERC #8				444,308		29,975,464		29,975,464
31	Clatskanie Peoples Utility District	AD	FERC #8				(9)			[(p)](2,025)	(2,025)
32	Clatskanie Peoples Utility District	OS	FERC #8				6,485		404,243		404,243
33	ConocoPhillips Company	AD	FERC #8				132			[(q)](8,850)	(8,850)
34	ConocoPhillips Company	OS	FERC #8				694,051		49,643,883		49,643,883
35	Constellation Energy Generation, LLC	AD	FERC #8				147			[(r)]52,060	52,060
36	Constellation Energy Generation, LLC	OS	FERC #8				107,367		6,839,061		6,839,061
37	CP Energy Marketing (US) Inc.	OS	FERC #8				491		58,665		58,665
38	Dynasty Power Inc.	AD	FERC #8				2			[(s)]88	88
39	Dynasty Power Inc.	OS	FERC #8				84,264		5,558,513		5,558,513
40	EDF Trading N.A., LLC	OS	FERC #8				41,206		2,986,405		2,986,405
41	Energy Keepers, Inc.	AD	FERC #8				[(a)](8)				
42	Energy Keepers, Inc.	OS	FERC #8				504		46,706		46,706
43	Eugene Water & Electric Board	AD	FERC #8				(51)			[(t)](6,525)	(6,525)
44	Eugene Water & Electric Board	OS	FERC #8				22,612		1,730,815		1,730,815
45	Grant County PUD No.2	OS	FERC #8				10,800		901,800		901,800
46	Grant County PUD No.2	OS	FERC #9				29		1,581		1,581
47	Gridforce Energy Management, LLC.	OS	FERC #9				790		61,503		61,503
48	Idaho Power Company	AD	FERC #8				(1,040)			[(u)](325,795)	(325,795)
49	Idaho Power Company	OS	FERC #8				28,649		2,116,197		2,116,197
50	Idaho Power Company	OS	FERC #9				70		3,674		3,674
51	Mercuria Energy America, LLC	OS	FERC #8				127,294		10,013,302		10,013,302
52	Merrill Lynch Commodities, Inc.	AD	FERC #8							[(v)](100)	(100)
53	Merrill Lynch Commodities, Inc.	OS	FERC #8				15,600		871,692		871,692
54	Morgan Stanley Capital Group Inc.	AD	FERC #8				(34)			[(w)](2,632)	(2,632)
55	Morgan Stanley Capital Group Inc.	OS	FERC #8				466,086		31,655,047		31,655,047
56	NaturEner Power Watch, LLC	OS	FERC #9				50		3,182		3,182
57	NorthWestern Energy	AD	FERC #8				(4)			[(x)](293)	(293)
58	NorthWestern Energy	OS	FERC #8				28,219		3,273,466		3,273,466
59	NorthWestern Energy	OS	FERC #9				35		1,838		1,838

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)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
60	PacifiCorp	OS	FERC #8				93,685		6,898,679		6,898,679
61	PacifiCorp	OS	FERC #9				64		8,297		8,297
62	Phillips 66 Energy Trading LLC	OS	FERC #8				22,340		1,647,425		1,647,425
63	Portland General Electric Company	OS	FERC #8				178,479		13,726,927		13,726,927
64	Portland General Electric Company	OS	FERC #9				54		3,799		3,799
65	Powerex Corp.	AD	FERC #8				40			[y]8,344	8,344
66	Powerex Corp.	OS	FERC #8				1,097,359		66,310,440		66,310,440
67	Rainbow Energy Marketing	OS	FERC #8				4,761		646,566		646,566
68	Sacramento Municipal Utility District	OS	FERC #9				60		3,822		3,822
69	Seattle City Light Marketing	OS	FERC #8				126,845		12,358,154		12,358,154
70	Seattle City Light Marketing	OS	FERC #9				13		848		848
71	Shell Energy North America (US)	AD	FERC #8							[z](1,000)	(1,000)
72	Shell Energy North America (US)	OS	FERC #8				1,279,706		97,465,614		97,465,614
73	Snohomish County PUD	AD	FERC #8				(12)			[aa](2,280)	(2,280)
74	Snohomish County PUD	OS	FERC #8				153,918		11,960,748		11,960,748
75	Tacoma Power	OS	FERC #8				26,105		1,603,928		1,603,928
76	Tacoma Power	OS	FERC #9				21		802		802
77	The Energy Authority	AD	FERC #8							[ab]400	400
78	The Energy Authority	OS	FERC #8				148,985		12,537,830		12,537,830
79	TransAlta Energy Marketing U.S.	AD	FERC #8				48			[ac]11,953	11,953
80	TransAlta Energy Marketing U.S.	OS	FERC #8				894,329		60,022,571		60,022,571
81	TransCanada Energy Sales Ltd.	OS	FERC #8				4,127		378,325		378,325
82	Vitol Inc.	OS	FERC #8				108,363		7,130,677		7,130,677
15	Subtotal - RQ						6,700	71,112	235,416	18,471	324,999
16	Subtotal-Non-RQ						9,026,924		640,780,730	(275,155)	640,505,575
17	Total						9,033,624	71,112	641,016,146	(256,684)	640,830,574

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: MegawattHoursSoldSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	—	—	(8)	(8)
Amount	$—	$—	$—	$—

*Bookouts of firm purchases treated as sales in EQR refiling but as a reduction of purchases for accounting purposes. Deemed immaterial.

(b) Concept: OtherChargesRevenueSalesForResale

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

(c) Concept: OtherChargesRevenueSalesForResale

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

(d) Concept: OtherChargesRevenueSalesForResale

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

(e) Concept: OtherChargesRevenueSalesForResale

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

(f) Concept: OtherChargesRevenueSalesForResale

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

(g) Concept: OtherChargesRevenueSalesForResale

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

(h) Concept: OtherChargesRevenueSalesForResale

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

(i) Concept: OtherChargesRevenueSalesForResale

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

(j) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	—	—	12	12
Amount	$500	$—	$850	$1,350

*Correction of December transaction in Q4 2023 EQR filing. Correction of General Ledger pending.

(k) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	(45)	—	—	(45)
Amount	($14,225)	$—	$—	($14,225)

(l) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	36	—	—	36
Amount	$14,277	$—	$—	$14,277

(m) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	—	—	—	—
Amount	$500	($424)	$—	$76

(n) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	—	—	—	—
Amount	$—	($30)	$—	($30)

(o) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	—	1	—	1
Amount	$—	$51	$1	$52

*Accounting adjustments not in EQR refiling. Deemed immaterial.

(p) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	(9)	—	—	(9)
Amount	($2,025)	$—	$—	($2,025)

(q) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	132	—	—	132
Amount	($9,758)	$908	$—	($8,850)

(r) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	147	—	—	147
Amount	$52,060	$—	$—	$52,060

(s) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	—	2	—	2
Amount	$—	$88	$—	$88

(t) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	(51)	—	—	(51)
Amount	($6,525)	$—	$—	($6,525)

(u) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	(1,040)	—	—	(1,040)
Amount	($325,795)	$—	$—	($325,795)

(v) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	—	—	—	—
Amount	$—	($100)	$—	($100)

(w) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	(34)	—	—	(34)
Amount	($6,104)	$3,472	$—	($2,632)

(x) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	—	(4)	—	(4)
Amount	$—	($293)	$—	($293)

(y) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	—	40	—	40
Amount	$—	$8,344	$—	$8,344

(z) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	—	—	—	—
Amount	$—	($1,000)	$—	($1,000)

(aa) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	(12)	—	—	(12)
Amount	($2,280)	$—	$—	($2,280)

(ab) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	—	—	—	—
Amount	$—	$400	$—	$400

(ac) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2022) Adjustments	Post Period (2024) Adjustments	EQR Corrections *	Total
MWH	85	(37)	—	48
Amount	$12,780	($827)	$—	$11,953

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,343,070	1,386,767
5	(501) Fuel	60,636,604	57,889,027
6	(502) Steam Expenses	7,228,080	6,461,530
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,189,193	1,850,235
10	(506) Miscellaneous Steam Power Expenses	9,363,394	9,838,218
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	80,760,341	77,425,777
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	648,211	1,027,119
16	(511) Maintenance of Structures	1,492,111	1,572,491
17	(512) Maintenance of Boiler Plant	12,693,388	10,200,516
18	(513) Maintenance of Electric Plant	6,870,087	3,777,527
19	(514) Maintenance of Miscellaneous Steam Plant	1,515,653	1,652,630
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	23,219,450	18,230,283
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	103,979,791	95,656,060
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-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	1,704,639	1,838,698
45	(536) Water for Power		
46	(537) Hydraulic Expenses	4,179,622	3,493,327
47	(538) Electric Expenses	341,918	278,163
48	(539) Miscellaneous Hydraulic Power Generation Expenses	794,658	1,916,301

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	7,020,837	7,526,489
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	82,141	61,778
54	(542) Maintenance of Structures	599,604	316,883
55	(543) Maintenance of Reservoirs, Dams, and Waterways	745,059	515,032
56	(544) Maintenance of Electric Plant	1,166,218	1,198,621
57	(545) Maintenance of Miscellaneous Hydraulic Plant	4,358,766	3,392,652
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,951,788	5,484,966
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	13,972,625	13,011,455
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	5,015,312	5,767,407
63	(547) Fuel	396,650,165	290,270,276
64	(548) Generation Expenses	17,137,575	14,012,624
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	4,482,527	4,076,263
66	(550) Rents	6,808,104	6,982,021
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	430,093,683	321,108,591
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	482,613	395,881
70	(552) Maintenance of Structures	640,722	744,224
71	(553) Maintenance of Generating and Electric Plant	25,160,551	32,559,417
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,372,704	1,249,908
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	27,656,590	34,949,430
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	457,750,273	356,058,021
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,008,414,381	1,043,007,858
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	28,612	28,612
78	(557) Other Expenses	94,142,017	(11,850,062)
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	1,102,585,010	1,031,186,408
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	1,678,287,699	1,495,911,944
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,765,563	3,459,252
85	(561.1) Load Dispatch-Reliability	44,962	43,541
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,909,347	2,084,722
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,334,024	941,407
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	1,901,460	1,835,915
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	2,675,677	2,476,217
92	(561.8) Reliability, Planning and Standards Development Services	(1,578,768)	66,314
93	(562) Station Expenses	1,383,406	1,288,208
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	(1,132,150)	390,690
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	162,583,424	144,916,422
97	(566) Miscellaneous Transmission Expenses	3,668,423	3,305,489
98	(567) Rents	338,210	398,644
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	176,893,578	161,206,821
100	Maintenance		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
101	(568) Maintenance Supervision and Engineering	107,618	21,613
102	(569) Maintenance of Structures	5,539	1,205
103	(569.1) Maintenance of Computer Hardware		41
104	(569.2) Maintenance of Computer Software	70,925	4,470
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,840,823	2,371,329
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	8,808,122	7,339,307
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	76,874	100,742
111	TOTAL Maintenance (Total of Lines 101 thru 110)	11,909,901	9,838,707
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	188,803,479	171,045,528
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 Operation Expenses (Enter Total of Lines 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,634,172	3,845,379
135	(581) Load Dispatching	1,544,259	1,233,905
136	(582) Station Expenses	2,448,778	2,046,281
137	(583) Overhead Line Expenses	6,167,558	4,788,508
138	(584) Underground Line Expenses	6,079,282	5,860,854
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	4,258,764	3,538,416
141	(587) Customer Installations Expenses	6,343,306	5,698,726
142	(588) Miscellaneous Expenses	13,730,791	10,714,945
143	(589) Rents	1,382,349	1,450,313
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	44,589,259	39,177,327
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	167,637	136,537
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	1,750,921	2,071,574
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	40,799,400	40,470,707
150	(594) Maintenance of Underground Lines	16,272,732	13,977,521
151	(595) Maintenance of Line Transformers	177,127	724,550
152	(596) Maintenance of Street Lighting and Signal Systems	4,000,597	2,984,435

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
153	(597) Maintenance of Meters	889,059	720,967
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of Lines 146 thru 154)	64,057,473	61,086,291
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	108,646,732	100,263,618
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	179,971	123,215
160	(902) Meter Reading Expenses	12,674,729	12,142,113
161	(903) Customer Records and Collection Expenses	28,438,912	24,224,347
162	(904) Uncollectible Accounts	18,488,205	18,549,268
163	(905) Miscellaneous Customer Accounts Expenses	188,225	
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	59,970,042	55,038,943
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	144,569,269	132,966,770
169	(909) Informational and Instructional Expenses	2,499,407	1,882,235
170	(910) Miscellaneous Customer Service and Informational Expenses	219	
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	147,068,895	134,849,005
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,231,798	969,613
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	1,231,798	969,613
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	78,570,677	69,794,998
182	(921) Office Supplies and Expenses	7,463,412	5,878,079
183	(Less) (922) Administrative Expenses Transferred-Credit	32,365,661	27,808,615
184	(923) Outside Services Employed	20,765,085	16,764,046
185	(924) Property Insurance	6,318,020	6,082,479
186	(925) Injuries and Damages	8,919,311	5,217,662
187	(926) Employee Pensions and Benefits	28,392,494	30,682,128
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	16,043,545	18,424,521
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	56,129	55,714
192	(930.2) Miscellaneous General Expenses	9,187,393	7,615,337
193	(931) Rents	10,338,554	9,673,159
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	153,688,959	142,379,508
195	Maintenance		
196	(935) Maintenance of General Plant	18,392,095	17,767,627
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	172,081,054	160,147,135
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	2,356,089,699	2,118,225,786

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

PURCHASED POWER (Account 555)

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.

   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, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) 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 (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) 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 columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

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)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)
1	[a] 3 Bar G Wind Turbine #3 LLC	LU					31			
2	[b] Avangrid Renewable (Golden Hills)	AD								
3	[c] Avangrid Renewable (Golden Hills)	LU					652,698			
4	Avista Corp. WWP Division	EX								130
5	Avista Corp. WWP Division	OS					55,908			
6	[d] Avista Nichols Pump	EX							15,024	
7	[e] Powerex (Point Roberts)	AD								
8	[f] Powerex (Point Roberts)	IF					20,317			
9	[g] BIO ENERGY (Washington) LLC	LU					435			
10	[h] Black Creek Hydro	LU					8,646			
11	[i] Bloks Evergreen Dairy	LU					35			
12	[j] BP Energy Co.	AD					196			
13	BP Energy Co.	OS					60,084			
14	Bonneville Power Admistration	OS					590,286			
15	[k] Bonneville Power Admistration	LF								
16	[l] Brookfield Energy Marketing LP	AD					(69)			
17	Brookfield Energy Marketing LP	OS					1,713			
18	[m] CA Carbon Obligation	AD								
19	California ISO - EIM Purchases	OS					1,367,292			
20	California ISO	OS					120,649			
21	[n] CAMAS SOLAR	LU					10,429			
22	[o] Cascade Community Solar	IU					30			
23	Chelan County PUD #1	OS					47,914			
24	[p] Chelan PUD - Rock Island and Rocky Reach	LU					1,640,658			
25	[q] Chelan PUD Slice 35	LU					323,977			
26	[r] Citigroup Energy (Financial)	OS								
27	[s] Citigroup Energy Inc	AD					112			
28	Citigroup Energy Inc	OS					376,306			
29	[t] Clatskanie PUD	AD					75			
30	Clatskanie PUD	OS					1,829			
31	[u] Clearwater Wind	AD					121			
32	[v] Clearwater Wind	LU					1,311,795			
33	[w] Conoco, Inc.	AD					(76)			
34	Conoco, Inc.	OS					276,574			
35	[x] CONSTELLATION ENERGY	AD					(287)			
36	CONSTELLATION ENERGY	OS					8,260			
37	CP Energy Marketing (Epcor)	OS					3,688			
38	System Deviation	EX							11,042	210,763

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)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)
39	[y] Douglas County PUD #1	AD					4,576			
40	[z] Douglas PUD - Wells Project	IU					166,570			
41	[aa] Douglas PUD - Wells Project	AD								
42	[ab] Douglas PUD - Wells Project	LU					831,001			
43	DYNASTY POWER INC	OS					1,905			
44	[ac] Edaleen Dairy, LLC	OS					3,753			
45	EDF Trading NA LLC	OS					2,237			
46	[ad] Emerald City Renewables, LLC	LU					33,975			
47	Energy Keepers Inc.	OS					800			
48	[ae] Eugene Water & Electric	AD					(75)			
49	Eugene Water & Electric	OS					6,614			
50	[af] Farm Power Rexville LLC	LU					3,718			
51	[ag] Grant County PUD #2	AD								
52	Grant County PUD #2	OS					19			
53	[ah] Grant PUD - Priest Rapids Project	AD								
54	[ai] Grant PUD - Priest Rapids Project	LU					333,842			
55	[aj] Green Direct RECs	AD								
56	Gridforce Energy Management, LLC.	OS					15			
57	[ak] HF Sinclair (Mar Pt)	IU					327,676			
58	[al] Avangrid Renewables (PPM Energy)	AD					(17)			
59	Avangrid Renewables (PPM Energy)	OS					200,610			
60	Idaho Power Company	OS					3,382			
61	[am] Ikea U.S. West, Inc.	LU					35			
62	[an] KERR DAM-ENERGY KEEPER	LU					350,361			
63	[ao] Avangrid Renewables (Klondike Wind Power III)	AD								
64	[ap] Avangrid Renewables (Klondike Wind Power III)	LU					115,990			
65	[aq] Knudsen Wind Turbine#1	LU					5			
66	[ar] Koma Kulshan Associates	LU					26,187			
67	[as] Lake Washington School District #414	LU					206			
68	[at] Lund Hill Solar, LLC	AD								
69	[au] Lund Hill Solar, LLC	LU					291,130			
70	[av] MERCURIA ENERGY	AD					(141)			
71	[aw] Morgan Stanley CG	AD					(206)			
72	[ax] Morgan Stanley CG	LF					243,042			
73	Morgan Stanley CG	OS					38,181			
74	[ay] Puget Sound Hydro (Nooksack)	OS					15,008			
75	Northwestern Energy	OS					20,278			

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)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)
76	[az] Pacific Gas & Elec - Exchange	EX							413,000	413,000
77	Pacificorp	OS					11,081			
78	[ba] Penstemon Solar	LU					10,492			
79	[bb] Port of Coupeville	OS					57			
80	Portland General Electric	OS					20,152			
81	[bc] Powerex Corp.	AD					(18)			
82	Powerex Corp.	EX							60	70
83	Powerex Corp.	OS					32,090			
84	[bd] Powerex Summer Capacity	IF					488,000			
85	[be] Powerex Winter Capacity	IF					1,208,000			
86	Rainbow Energy Marketing	OS					2,105			
87	[bf] Rainer BioGas	LU					4,038			
88	[bg] Residential Exchange	AD								
89	Sacramento Municipal	OS					160			
90	[bh] Seattle City Light Marketing	AD								
91	Seattle City Light Marketing	OS					41,692			
92	Shell Energy (Coral Pwr)	OS					474,143			
93	[bi] Sierra Pacific Industries	AD								
94	[bj] Sierra Pacific Industries	LU					135,153			
95	[bk] Skookumchuck Hydro	LU					3,050			
96	[bl] Skookumchuck Wind PPA	LU					415,029			
97	Snohomish County PUD #1	OS					13,665			
98	[bm] Swauk Wind LLC	OS					5,966			
99	[bn] Hillside Clean Energy (Sygitowicz)	LU					781			
100	[bo] TACOMA GLASS	OS					185			
101	Tacoma Power	OS					27,844			
102	[bp] The Energy Authority	AD								
103	The Energy Authority	OS					51,143			
104	[bq] Transalta Centralia Generation LLC	AD					171			
105	[br] Transalta Centralia Generation LLC	LU					3,326,405			
106	[bs] TransAlta Energy Marketing	AD					(404)			
107	TransAlta Energy Marketing	OS					352,987			
108	TransCanada Energy Sales Ltd	OS					14			
109	Turlock Irrigation District	OS					2,032			
110	[bt] Twin Falls Hydro	LU					49,979			
111	[bu] URTICA SOLAR	LU					11,509			
112	[bv] VanderHaak Dairy Digester	IU					4,398			
113	Vitol Inc.	OS					2,853			
114	[bw] Washington Emission Allowance	AD								

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)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)
115	(bx) South Fork II Associates(Weeks Falls)	OS					8,699			
116	(by) Wells Fargo (Financial)	OS								
15	TOTAL						16,603,754		439,126	623,963

Line No.	COST/SETTLEMENT OF POWER			
	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1		929		929
2			2,001,303	2,001,303
3		31,605,562		31,605,562
4		(8,560)		(8,560)
5		4,476,098		4,476,098
6		1,151,527		1,151,527
7			19,583	19,583
8		1,860,532		1,860,532
9		14,837		14,837
10		446,563		446,563
11		2,513		2,513
12			39,527	39,527
13		3,455,065		3,455,065
14		46,854,402		46,854,402
15		9,432,000		9,432,000
16			(19,166)	(19,166)
17		205,138		205,138
18			527,163	527,163
19		53,201,292		53,201,292
20		8,359,562		8,359,562
21		758,477		758,477
22		1,173		1,173
23		2,176,489		2,176,489
24		35,279,808	43,171,190	78,450,998
25		17,319,245	11,487	17,330,732
26		(2,361,405)		(2,361,405)
27			23,483	23,483
28		30,183,381		30,183,381
29			15,750	15,750
30		111,625		111,625
31			(308,668)	(308,668)
32		33,121,305		33,121,305
33			(26,316)	(26,316)
34		26,596,743		26,596,743
35			(101,027)	(101,027)
36		424,582		424,582
37		315,900		315,900
38				
39			1,309,429	1,309,429
40		8,340,000		8,340,000
41			(68,747)	(68,747)
42		32,703,829		32,703,829
43		203,290		203,290
44		179,714		179,714
45		131,470		131,470
46		2,501,553		2,501,553
47		93,480		93,480
48			(15,750)	(15,750)
49		386,015		386,015
50		174,180		174,180
51			330,417	330,417
52		1,703		1,703
53			200,319	200,319

Line No.	COST/SETTLEMENT OF POWER			
	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
54		44,443,985		44,443,985
55			309,492	309,492
56		1,106		1,106
57		28,377,506		28,377,506
58			(3,297)	(3,297)
59		20,063,202		20,063,202
60		186,933		186,933
61		2,560		2,560
62		16,641,768		16,641,768
63			(7,836)	(7,836)
64		8,585,918		8,585,918
65		136		136
66		2,201,758		2,201,758
67		8,003		8,003
68			(244,786)	(244,786)
69		10,776,222		10,776,222
70			(23,391)	(23,391)
71			(9,775)	(9,775)
72		11,532,343		11,532,343
73		2,379,426		2,379,426
74		718,592		718,592
75		1,302,139		1,302,139
76				
77		683,394		683,394
78		763,117		763,117
79		2,198		2,198
80		1,893,342		1,893,342
81			(2,099)	(2,099)
82		(1,000)		(1,000)
83		7,572,261		7,572,261
84		51,069,200		51,069,200
85		142,483,600		142,483,600
86		222,798		222,798
87		189,188		189,188
88			(77,223,142)	(77,223,142)
89		11,025		11,025
90			187,000	187,000
91		2,722,888		2,722,888
92		43,537,127		43,537,127
93			(10,147)	(10,147)
94		5,959,942		5,959,942
95		103,122		103,122
96		19,618,210		19,618,210
97		371,994		371,994
98		252,232		252,232
99		56,799		56,799
100		6,725		6,725
101		2,851,486		2,851,486
102			(500)	(500)
103		2,617,691		2,617,691
104			408,175	408,175
105		192,038,428		192,038,428
106			(176,663)	(176,663)

Line No.	COST/SETTLEMENT OF POWER			
	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
107		30,304,798		30,304,798
108		495		495
109		42,090		42,090
110		3,748,395		3,748,395
111		837,065		837,065
112		149,964		149,964
113		225,850		225,850
114			95,942,000	95,942,000
115		416,516		416,516
116		(65,513,180)		(65,513,180)
15		942,159,374	66,255,008	1,008,414,382

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

3 Bar G Wind Turbine #3 LLC Contract Expires Dec, 2029

(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Avangrid Renewable (Golden Hills) Prior period adjustment

(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Avangrid Renewable (Golden Hills) Contract Expires Apr, 2042

(d) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Avista Nichols Pump Contract Expires Dec, 2025

(e) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Powerex (Point Roberts) Prior period adjustment

(f) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Powerex (Point Roberts) Contract Expires Sep, 2025

(g) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

BIO ENERGY (Washington) LLC Contract Expires Dec, 2026

(h) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Black Creek Hydro Contract Expires Dec, 2032

(i) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Bloks Evergreen Dairy Contract Expires Dec, 2031

(j) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

BP Energy Co. Prior period adjustment

(k) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Bonneville Power Admistration Contract Expires Dec, 2026

(l) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Brookfield Energy Marketing Prior period adjustment

(m) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

CA Carbon Allowance

(n) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

CAMAS SOLAR Contract Expires Dec, 2036

(o) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Cascade Community Solar Contract Expires Dec, 2024

(p) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Chelan PUD - Rock Island and Rocky Reach Contract Expires Oct, 2031Administrative $ 9,978,834Amortization $ 7,709,655Debt Service $18,466,905RECs $ 7,015,796Total $43,171,190

(q) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Chelan PUD Slice 35 Contract Expires Dec, 2026Administrative $11,487

(r) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Citigroup Energy Power Financial Hedging Transactions

(s) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Citigroup Energy Inc Prior period adjustment

(t) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Clatskanie PUD Prior period adjustment

(u) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Clearwater Wind Prior period adjustment

(v) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Clearwater Wind Contract Expires Nov, 2047

(w) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Conoco, Inc. Prior period adjustment

(x) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

CONSTELLATION ENERGY Prior period adjustment

(y) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Douglas County PUD #1 Prior period adjustment

(z) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Douglas PUD - Wells Project Contract Expires Sep, 2024

(aa) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Douglas PUD - Wells Project Prior period adjustment

(ab) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Douglas PUD - Wells Project Contract Expires Sep, 2028

(ac) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Edaleen Dairy, LLC Contract Expired Dec, 2023

(ad) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Emerald City Renewables, LLC Contract Expires Dec, 2029

(ae) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Eugene Water & Electric Prior period adjustment

(af) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Farm Power Rexville LLC Contract Expires Dec, 2032

(ag) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Grant County PUD #2 Frequency Response

(ah) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Grant PUD - Priest Rapids Project Prior period adjustment
(ai) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Grant PUD - Priest Rapids Project Contract Expires Apr, 2052
(aj) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Green Direct RECs
(ak) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
HF Sinclair (Mar Pt) Contract Expires Sep, 2025
(al) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Avangrid Renewables (PPM Energy) Prior period adjustment
(am) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Ikea U.S. West, Inc. Contract Expires Dec, 2031
(an) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
KERR DAM-ENERGY KEEPER Contract Expires Jul, 2035
(ao) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Klondike Wind Power III Prior period adjustment
(ap) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Avangrid Renewables (Klondike Wind Power III) Contract Expires Nov, 2027
(aq) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Knudsen Wind Turbine#1 Contract Expires Dec, 2029
(ar) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Koma Kulshan Associates Contract Expires Mar, 2037
(as) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Lake Washington School District #414 Contract Expires Dec, 2032
(at) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Lund Hill Solar, LLC Prior period adjustment
(au) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Lund Hill Solar, LLC Contract Expires Oct, 2042
(av) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
MERCURIA ENERGY Prior period adjustment
(aw) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Morgan Stanley CG Prior period adjustment
(ax) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Morgan Stanley CG Contract Expires Dec, 2026
(ay) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Puget Sound Hydro (Nooksack) Contract Expired Dec, 2023
(az) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Pacific Gas & Elec - Exchange Contract Expires Dec, 2027
(ba) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Penstemon Solar Contract Expires Dec, 2036
(bb) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Port of Coupeville Contract Expired Dec, 2023
(bc) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Powerex Corp. Prior period adjustment
(bd) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Powerex Summer Capacity Contract Expires Sep, 2024
(be) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Powerex Winter Capacity Contract Expires Mar, 2024
(bf) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Rainer BioGas Contract Expires Dec, 2032
(bg) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Residential Exchange
(bh) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Seattle City Light Marketing Frequency Response
(bi) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Sierra Pacific Industries Prior period adjustment
(bj) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Sierra Pacific Industries Contract Expires Dec, 2037
(bk) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Skookumchuck Hydro Contract Expires Dec, 2025
(bl) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Skookumchuck Wind PPA Contract Expires Nov, 2040
(bm) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Swauk Wind LLC Contract Expired Dec, 2023
(bn) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Hillside Clean Energy (Sygitowicz) Contract Expires Dec, 2030
(bo) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
TACOMA GLASS Contract Expired Dec, 2023
(bp) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
The Energy Authority Prior period adjustment
(bq) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Transalta Centralia Generation LLC Prior period adjustment
(br) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Transalta Centralia Generation LLC Contract Expires Dec, 2025
(bs) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

TransAlta Energy Marketing Prior period adjustment
(bt) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Twin Falls Hydro Contract Expires Feb, 2025
(bu) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
URTICA SOLAR Contract Expires Dec, 2036
(bv) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
VanderHaak Dairy Digester Contract Expired Dec, 2023
(bw) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Washington Emission Allowance per Chapter 173-441 WAC
(bx) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
South Fork II Associates(Weeks Falls) Contract Expired Dec, 2023
(by) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Wells Fargo Power Financial Hedging Transactions

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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.
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.
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 (0) 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.

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)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY	
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)
1	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	OS	[x] FRS #60	Beverly Park Substn	Goldbar Substation	[ad] 0		
2	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	[a] OLF	[y] FRS #28	Beverly Park Substn	Hilton Lake Substn	[ae] 0	80,681	80,681
3	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	[b] OLF	[z] FRS #28	Beverly Park Substn	Olympic Pipe Substn	[af] 0	10,241	10,241
4	Tacoma City Light	Tacoma City Light	Tacoma City Light	[c] OS	[aa] FRS #62	Starwood Substation	Baldi Substation	[ag] 0		
5	Bonneville Power Administration	Bonneville Power Admin	City of Blaine	FNO	[ab] PSE OATT	Custer Substation	Blaine&Semiahmo Sub	[ah] 0	84,296	84,296
6	Bonneville Power Administration	Bonneville Power Admin	City of Sumas	FNO	PSE OATT	Bellingham Substn	City of Sumas Sub	[ai] 0	33,591	33,591
7	Bonneville Power Administration	Bonneville Power Admin	Kittitas County PUD	FNO	PSE OATT	White River Substn	Teanaway Substation	[aj] 0	24,180	24,180
8	Bonneville Power Administration	Bonneville Power Admin	Orcas Power & Light	FNO	PSE OATT	Murray Bellingham	Fidalgo Substation	[ak] 0	234,761	234,761
9	Bonneville Power Administration	Bonneville Power Admin	Tanner Electric Cooperative	FNO	PSE OATT	Maple Valley Substn	Ames Lake Tap	[al] 0	22,813	22,813
10	Bonneville Power Administration	Bonneville Power Admin	Tanner Electric Cooperative	FNO	PSE OATT	Olympia Substation	Luhr Beach Tap	[am] 0	16,018	16,018
11	Bonneville Power Administration	Bonneville Power Admin	Tanner Electric Cooperative	FNO	PSE OATT	Maple Valley Substn	North Bend Substn	[an] 0		
12	Bonneville Power Administration	Bonneville Power Admin	Port of Seattle and Various	FNO	PSE OATT	Various	Sea Tac Airport	[ao] 0	144,895	144,895
13	Bonneville Power Administration	Bonneville Power Admin	Lewis County PUD	FNO	PSE OATT	BPAT.PSEI	Tono Substation	[ap] 0	1,268	1,268
14	Morgan Stanley Capital Group, Inc	Various	Various	[d] LFP	PSE OATT	John Day, COB	John Day, COB	100	876,000	876,000
15	Morgan Stanley Capital Group	Various	Various	[e] LFP	PSE OATT	Various Washington	Various Washington	90	788,400	788,400
16	Powerex	Various	Various	[f] LFP	PSE OATT	John Day, COB	John Day, COB	225	1,912,764	1,912,764
17	Powerex.	Various	Various	[g] LFP	PSE OATT	Various Washington	Various Washington			
18	Powerex..	Various	Various	[h] LFP	PSE OATT	Various Washington	Various Washington	88	770,880	770,880
19	Seattle City Light	Various	Various	[i] LFP	PSE OATT	Various Washington	Various Washington	16	140,160	140,160
20	TransAlta Energy	Various	Various	[j] LFP	PSE OATT	John Day, COB	John Day, COB	75	642,600	642,600
21	TransAlta Energy.	Various	Various	[k] LFP	PSE OATT	Various Washington	Various Washington			
22	Vantage Wind Energy LLC-Invenergy	Various	Various	[l] LFP	PSE OATT	Various Washington	Various Washington			
23	Whatcom County PUD	Whatcom County PUD	Whatcom County PUD	[m] LFP	PSE OATT	Custer Substation	Enterprise Sub	2	17,520	17,520
24	Sierra Pacific	Various	Various	LFP	PSE OATT	Various Washington	Various Washington			
25	Shell Energy North America	Various	Various	SFP	PSE OATT	Various Washington	Various Washington	584	140,175	140,175
26	Guzman Energy	Various	Various	SFP	PSE OATT	John Day, COB	John Day, COB	6	4,464	4,464
27	Avangrid Renewables	Various	Various	SFP	PSE OATT	John Day, COB	John Day, COB	60	43,776	43,776
28	Powerex	Various	Various	SFP	PSE OATT	John Day, COB	John Day, COB	18	3,456	3,456
29	Powerex.	Various	Various	SFP	PSE OATT	Various Washington	Various Washington	2,620	119,580	119,580
30	Snohomish County PUD	Various	Various	SFP	PSE OATT	Various Washington	Various Washington	1,337	38,075	38,075
31	TransAlta Energy	Various	Various	SFP	PSE OATT	Various Washington	Various Washington	525	14,400	14,400
32	Vitol, Inc.	Various	Various	SFP	PSE OATT	Various Washington	Various Washington	150	73,200	73,200
33	Avista Corporation	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		4,504	4,504
34	Avista Corporation.	Various	Various	NF	PSE OATT	Various Washington	Various Washington		6,153	6,153

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)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY	
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)
35	Brookfield Renewables	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		4,665	4,665
36	Shell Energy North America	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		14,822	14,822
37	Shell Energy North America.	Various	Various	NF	PSE OATT	Various Washington	Various Washington		5,575	5,575
38	Dynasty Power Inc	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		158,079	158,079
39	Dynasty Power Inc.	Various	Various	NF	PSE OATT	Various Washington	Various Washington		550	550
40	CP Energy Marketing	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		3,317	3,317
41	Exelon Generation	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		17,855	17,855
42	Guzman Energy	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		145,071	145,071
43	Macquarie Energy, LLC	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		24,861	24,861
44	Mercuria Energy	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		16,306	16,306
45	Mercuria Energy.	Various	Various	NF	PSE OATT	Various Washington	Various Washington		30	30
46	Morgan Stanley Capital Group, Inc	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		14,838	14,838
47	Portland General Electric	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		58,023	58,023
48	Avangrid Renewable, LLC	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		376	376
49	Powerex	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		119,189	119,189
50	Powerex.	Various	Various	NF	PSE OATT	Various Washington	Various Washington		86,019	86,019
51	Rainbow Energy Marketing	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		50,854	50,854
52	Seattle City Light	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		285	285
53	Sacramento Municipal Utility District	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		145	145
54	Snohomish County PUD	Various	Various	NF	PSE OATT	Various Washington	Various Washington		7,330	7,330
55	The Energy Authority	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		122,278	122,278
56	TransAlta Energy	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		5,479	5,479
57	TransAlta Energy.	Various	Various	NF	PSE OATT	Various Washington	Various Washington		455	455
58	Turlock Irrigation Distric	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		2	2
59	Tacoma Power	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		40	40
60	Tacoma Power.	Various	Various	NF	PSE OATT	Various Washington	Various Washington		2,821	2,821
61	Vitol, Inc.	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		14,743	14,743
62	Air Liquide	Various	Air Liquide	(n) FNO	PSE OATT	(ac) Rocky Reach 115KV Sw	Air Liquide		69,809	69,809
63	Air Products	Various	Air Products	(o) FNO	PSE OATT	Rocky Reach 115KV Sw	Air Products		52,051	52,051
64	AMCOR Rigid Plastics	Various	AMCOR Rigid Plastics USA	(p) FNO	PSE OATT	Rocky Reach 115KV Sw	AMCOR Rigid Plastics		44,954	44,954
65	Bellingham Cold Storage - Roeder	Various	Bellingham Cold Storage - Roeder	(q) FNO	PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Roed		18,604	18,604
66	Bellingham Cold Storage - Orchard	Various	Bellingham Cold Storage - Orchar	(r) FNO	PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Orch		17,875	17,875
67	Boeing	Various	Boeing	(s) FNO	PSE OATT	Rocky Reach 115KV Sw	Boeing		364,341	364,341
68	BP Products North America Inc	Various	BP Products North America	(t) FNO	PSE OATT	Rocky Reach 115KV Sw	BP Products North America Inc		787,178	787,178
69	Center Drive Owners Association	Various	Center Drive Owners	(u) FNO	PSE OATT	Rocky Reach 115KV Sw	Center Drive Owners		4,209	4,209
70	HollyFrontier Puget Sound Refining	Various	HollyFrontier	(v) FNO	PSE OATT	Rocky Reach 115KV Sw	HollyFrontier		334,922	334,922

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)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatt Hours Received (i)	Megawatt Hours Delivered (j)
71	Tesoro Refining & Marketing CMP	Various	Tesoro	(w) FNO	PSE OATT	Rocky Reach 115KV Sw	Tesoro		250,988	250,988
72	Air Liquide	Various	Air Liquide	AD	PSE OATT	Rocky Reach 115KV Sw	Air Liquide			
73	Air Products	Various	Air Products	AD	PSE OATT	Rocky Reach 115KV Sw	Air Products			
74	BP Products North America Inc	Various	BP Products North America	AD	PSE OATT	Rocky Reach 115KV Sw	BP Products North America			
75	Bellingham Cold Storage - Orchard	Various	Bellingham Cold Storage - Orchard	AD	PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Orch			
76	Center Drive Owners Association	Various	Center Drive Owners	AD	PSE OATT	Rocky Reach 115KV Sw	Center Drive Owners			
77	AMCOR Rigid Plastics USA	Various	AMCOR Rigid Plastics USA	AD	PSE OATT	Various Washington	Various Washington			
78	Boeing	Various	Boeing	AD	PSE OATT	Various Washington	Various Washington			
79	Bonneville Power Administration	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
80	Brookfield Renewables	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
81	Dynasty Power Inc	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
82	Guzman Energy	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
83	HollyFrontier Puget Sound	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
84	Macquarie Energy, LLC	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
85	Mercuria Energy	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
86	Morgan Stanley Capital Group, Inc.	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
87	Portland General Electric Company	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
88	Avangrid Renewables	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
89	Powerex	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
90	Rainbow Energy Marketing Corporation	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
91	Seattle City Light	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
92	Snohomish Co. PUD	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
93	The Energy Authority	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
94	TransAlta Energy	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
95	Tesoro	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
96	Vitol, Inc.	Various	Various	AD	PSE OATT	Various Washington	Various Washington			
97	Whatcom County PUD	Whatcom County PUD	Whatcom County PUD	AD	PSE OATT	Custer Substation	Enterprise Sub			
35	TOTAL							5,896	9,067,790	9,067,790

Line No.	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1			[aq]600	600
2	9,615		[ar]600	10,215
3	1,554		[as]600	2,154
4			[at]4,195	4,195
5	302,524		[au]389,691	692,215
6	109,036		[av]313,294	422,330
7	104,980		[aw]123,703	228,683
8	815,295		[ax]671,194	1,486,489
9	93,389		[ay]84,105	177,494
10	68,492		[az]92,298	160,790
11	373,912		[ba]240,569	614,481
12	410,555		[bb]539,460	950,015
13	6,716		[bc]8,627	15,343
14	889,400		[bd]932,144	1,821,544
15	2,054,459		[be]2,613,274	4,667,733
16	1,941,315		[bf]1,037,391	2,978,706
17			[bg]89,025	89,025
18	2,010,985		[bh]1,278,389	3,289,374
19	365,634		[bi]34,427	400,061
20	652,292		[bj]243,300	895,592
21			[bk]4,012	4,012
22	2,230		[bl]90	2,320
23	45,704		[bm]29,501	75,205
24			[bn]7	7
25	430,642		[bo]484,913	915,555
26	4,268		[bp]606	4,874
27	44,828		[bq]11,857	56,685
28	3,425		[br]486	3,911
29	350,206		[bs]62,326	412,532
30	120,298		[bt]60,497	180,795
31	36,690		[bu]2,224	38,914
32	171,260		[bv]19,816	191,076
33		6,657	[bw]6,165	12,822
34		16,973	[bx]27,399	44,372
35		5,547	[by]6,285	11,832
36		19,879	[bz]12,919	32,798
37		25,104	[ca]32,626	57,730
38		191,872	[cb]68,242	260,114
39		1,945	[cc]959	2,904
40		3,797	[cd]3,629	7,426
41		21,105	[ce]12,225	33,330
42		170,692	[cf]95,404	266,096
43		28,016	[cg]54,236	82,252
44		21,587	[ch]25,666	47,253
45		121	[ci]43	164
46		17,451	[cj]4,085	21,536
47		79,886	[ck]43,055	122,941
48		689	[cl]158	847
49		177,508	[cm]76,422	253,930
50		321,911	[cn]224,155	546,066
51		61,872	[co]45,366	107,238
52		493	[cp]312	805
53		248	[cq]65	313

Line No.	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
54		29,098	[cr]15,171	44,269
55		169,974	[cs]304,947	474,921
56		7,119	[ct]4,686	11,805
57		2,420	[cu]771	3,191
58		3	0	3
59		73	[cv]9	82
60		10,096	[cw]1,012	11,108
61		17,492	[cx]39,505	56,997
62	179,749		[cy]197,599	377,348
63	114,094		[cz]126,319	240,413
64	115,946		[da]182,922	298,868
65	52,418		[db]56,046	108,464
66	48,452		[dc]53,208	101,660
67	1,113,259		[dd]1,054,525	2,167,784
68	2,120,090		[de]2,199,017	4,319,107
69	12,954		[df]19,919	32,873
70	863,939		[dg]1,079,825	1,943,764
71	672,291		[dh]804,278	1,476,569
72			[di](29)	(29)
73			[dj](13)	(13)
74			[dk](328)	(328)
75			[dl](18)	(18)
76			[dm](2)	(2)
77			[dn](16)	(16)
78			[do](152)	(152)
79			[dp](286)	(286)
80			[dq](26)	(26)
81			[dr](17)	(17)
82			[ds](100)	(100)
83			[dt](137)	(137)
84			[du](1)	(1)
85			[dv](74)	(74)
86			[dw](605)	(605)
87			[dx](32)	(32)
88			[dy](5)	(5)
89			[dz](1,084)	(1,084)
90			[ea](40)	(40)
91			[eb](55)	(55)
92			[ec](1)	(1)
93			[ed](95)	(95)
94			[ee](261)	(261)
95			[ef](109)	(109)
96			[eg](13)	(13)
97			[eh](7)	(7)
35	16,712,896	1,409,628	16,248,890	34,371,414

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode

Contract expires with two years written notice.

(b) Concept: StatisticalClassificationCode

Contract expires with two years written notice.

(c) Concept: StatisticalClassificationCode

Use of facilities on pre-888 contract with Baldi substation. Contract expires every 10 years but is automatically renewed unless otherwise requested.

(d) Concept: StatisticalClassificationCode

Contract expires August 1, 2025.

(e) Concept: StatisticalClassificationCode

Contract expires October 1, 2025.

(f) Concept: StatisticalClassificationCode

Powerex LFP 225 MW - Inlcudes three contracts wiht the following end dates: 25 MW - October 1, 2027; 100 MW - September 1, 2028; 100 MW - September 1, 2024

(g) Concept: StatisticalClassificationCode

Powerex LFP 225 MW - Inlcudes three contracts wiht the following end dates: 25 MW - October 1, 2027; 100 MW - September 1, 2028; 100 MW - September 1, 2024

(h) Concept: StatisticalClassificationCode

Contract expires on April 1, 2024.

(i) Concept: StatisticalClassificationCode

Contract expires on July 1, 2025.

(j) Concept: StatisticalClassificationCode

Contract expires on October 1, 2027 (25MW) and January 1, 2027 (50MW).

(k) Concept: StatisticalClassificationCode

Contract expires on October 1, 2027 (25MW) and January 1, 2027 (50MW).

(l) Concept: StatisticalClassificationCode

Contract expires on July 1, 2025.

(m) Concept: StatisticalClassificationCode

Contract expires with one year written notice.

(n) Concept: StatisticalClassificationCode

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

(o) Concept: StatisticalClassificationCode

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

(p) Concept: StatisticalClassificationCode

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

(q) Concept: StatisticalClassificationCode

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 459.

(r) Concept: StatisticalClassificationCode

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 459.

(s) Concept: StatisticalClassificationCode

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

(t) Concept: StatisticalClassificationCode

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

(u) Concept: StatisticalClassificationCode

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

(v) Concept: StatisticalClassificationCode

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

(w) Concept: StatisticalClassificationCode

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 459.

(x) Concept: RateScheduleTariffNumber

Grandfathered Exchange and Transfer Agreement for service to Snohomish County PUD's Goldbar substation.

(y) Concept: RateScheduleTariffNumber

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Hilton Lake substation.

(z) Concept: RateScheduleTariffNumber

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Olympic Pipe substation.

(aa) Concept: RateScheduleTariffNumber

Grandfathered Transfer Agreement with the City of Tacoma where Puget Sound Energy transfers transmission and energy to Tacoma's North Fork Well Field Complex.

(ab) Concept: RateScheduleTariffNumber

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.

(ac) Concept: TransmissionPointOfReceipt

Full name of the point of receipt is Rocky Reach 115KV Switchyard.

(ad) Concept: BillingDemand

Grandfathered Exchange and Transfer Agreement for service to Snohomish County PUD's Goldbar substation.

(ae) Concept: BillingDemand

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Hilton Lake substation.

(af) Concept: BillingDemand

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Olympic Pipe substation.

(ag) Concept: BillingDemand

Grandfathered Transfer Agreement with the City of Tacoma where Puget Sound Energy transfers transmission and energy to Tacoma's North Fork Well Field Complex.

(ah) Concept: BillingDemand

Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.
(ai) Concept: BillingDemand
Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.
(aj) Concept: BillingDemand
Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.
(ak) Concept: BillingDemand
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(ao) Concept: BillingDemand
Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.
(ap) Concept: BillingDemand
Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.
(aq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities charges.
(ar) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities charges.
(as) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities charges.
(at) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities charges.
(au) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax, facilities fees and loss return charges.
(av) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(aw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ax) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ay) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ba) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(bd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(be) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(bf) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(bl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(bm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(bn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Loss return for prior year adjusment
(bo) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(bp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(bq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(br) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(bs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(bt) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(bu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(bv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(bw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(bx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(by) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(bz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ca) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ce) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ch) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ck) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(co) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(cq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cr) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(cs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(ct) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(cv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(cx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cy) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(cz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(da) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(db) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(dc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(dd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(de) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes ancillary services, Washington State tax and loss return charges.
(df) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(dg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(dh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(di) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(dm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(do) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dr) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(ds) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dt) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(du) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dy) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(ea) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(eb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(ec) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(ed) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(ee) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(ef) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(eg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(eh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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 Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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42					
43					

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 Tariff (d)	Total Revenue (e)
44					
45					
46					
47					
48					
49					
40	TOTAL				
	Page 331				

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

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			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin	[(a)] LFP			[(e)] 39,667,680		[(g)] 7,598,916	47,266,596
2	Bonneville Power Admin	[(b)] LFP	[(d)] 20,689,940	20,689,940	[(f)] 55,456,365		[(h)] 36,909,956	92,366,321
3	Bonneville Power Admin	SFP			70,500		[(i)] 20,830	91,330
4	Bonneville Power Admin	NF	47,241	47,241		266,242	[(j)] 46,833	313,075
5	Bonneville Power Admin	OS					[(k)] 12,505	12,505
6	Bonneville Power Admin	OS					[(l)] 7,296	7,296
7	Bonneville Power Admin	OS					[(m)] 6,121,386	6,121,386
8	Bonneville Power Admin	OS					[(n)] 30,000	30,000
9	Bonneville Power Admin	OS					[(o)] 4,485,550	4,485,550
10	Bonneville Power Admin	AD					[(p)] (144,780)	(144,780)
11	Avista Corp.	OS					[(q)] 197,555	197,555
12	Avista Corp.	NF	134,286	134,286		743,731		743,731
13	Dynasty Power, Inc.	OS					[(r)] (68,936)	(68,936)
14	Chelan County PUD	[(c)] OLF	2,260,917	2,260,917			[(s)] 5,713,230	5,713,230
15	Grant County PUD #2	OS					[(t)] 157,184	157,184
16	Iberdrola Renewables	OS					[(u)] (35,184)	(35,184)
17	Idaho Power Company	NF	1,419	1,419		5,775		5,775
18	Klickitat County PUD	OS	2,212,693	2,212,693			[(v)] 1,401,840	1,401,840
19	Klondike Wind Power III	OS					[(w)] 376,800	376,800
20	Klondike Wind Power III	AD					[(x)] (321)	(321)
21	Morgan Stanley CG	OS					[(y)] (287,582)	(287,582)
22	Northwestern Energy	SFP	231,288	231,288	1,140,799		[(z)] 28,266	1,169,065
23	Northwestern Energy	NF	74,656	74,656		386,970	[(aa)] 22,955	409,925
24	Northwestern Energy	OS					[(ab)] 824,531	824,531
25	Northwestern Energy	OS					[(ac)] 401,043	401,043
26	Northwestern Energy	AD					[(ad)] 4,378	4,378
27	Portland General Electric	NF	63	63		1,860		1,860
28	Seattle City Light Marketing	OS					[(ae)] 105,366	105,366
29	Shell Energy	OS					[(af)] (1,663)	(1,663)
30	Talen Energy Marketing	OS					[(ag)] 727,282	727,282
31	The Energy Authority	OS					[(ah)] (38,924)	(38,924)
32	TransAlta Energy Marketing	OS					[(ai)] 761,268	761,268
33	TransAlta Energy Marketing	OS					[(aj)] (405,341)	(405,341)
34	Whatcom County PUD #1	OS					[(ak)] 28,645	28,645
35	Whatcom County PUD #1	AD					[(al)] 48,217	48,217
36	Idaho Power Company	OS					[(am)] 3,499	3,499
37	Conoco	OS					[(an)] (241,795)	(241,795)
38	EDF Trading NA LLC	OS					[(ao)] (3,040)	(3,040)

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
39	Other	OS					[(ap)]1,500	1,500
40	PacifiCorp	NF	1,034	1,034		6,805	0	6,805
41	Portland General Electric	AD					[(aq)](1,403)	(1,403)
42	Snohomish County PUD	OS					[(ar)]55,586	55,586
43	Tacoma Power	OS					[(as)](4,800)	(4,800)
44	Vitol Co.	OS					[(at)](30,050)	(30,050)
45	Seattle City Light Marketing	OS					[(au)]8,100	8,100
	TOTAL		25,653,537	25,653,537	96,335,344	1,411,383	64,836,698	162,583,425

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FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode

Includes a contract with several tables with end dates ranging from March 2024 to July 2037.

(b) Concept: StatisticalClassificationCode

Includes a contract with several tables with end dates ranging from January 2024 to September 2028.

(c) Concept: StatisticalClassificationCode

Contract end date is October 31, 2031.

(d) Concept: TransmissionOfElectricityByOthersEnergyReceived

Total MWh's for BPA firm transmission is calculated to be 20,689,940. The calculation does not split the MWh's between the contracts for the long-term firm Mid-Columbia projects and the other long-term firm contracts and short-term firm contract, so the entire 20,689,940 MWH's is reported with the long-term firm contracts on Line 2.

(e) Concept: DemandChargesTransmissionOfElectricityByOthers

Fixed transmission capacity charges that are related to the contracts for the Mid-Columbia hydro projects.

(f) Concept: DemandChargesTransmissionOfElectricityByOthers

Fixed transmission capacity charges other than those related to the contracts for the Mid-Columbia hydro projects.

(g) Concept: OtherChargesTransmissionOfElectricityByOthers

Ancillary services.

(h) Concept: OtherChargesTransmissionOfElectricityByOthers

Charges are for ancillary services including all spin and supplemental spin reserves. There are spin and supplemental spin reserves for both firm and non-firm transmission but the reporting only shows it in total so reported all of the reserves with the firm transmission "other" charges on line 2.The amount also includes regulatory entries done to record interest that PSE received on a transmission deposit as customer interest, via credits to transmission expense. The total also includes loss return charges.

(i) Concept: OtherChargesTransmissionOfElectricityByOthers

Ancillary services.

(j) Concept: OtherChargesTransmissionOfElectricityByOthers

Ancillary services.

(k) Concept: OtherChargesTransmissionOfElectricityByOthers

NWPP Reserve Sharing Fee

(l) Concept: OtherChargesTransmissionOfElectricityByOthers

Use of facilities charges.

(m) Concept: OtherChargesTransmissionOfElectricityByOthers

Intertie charges and capacity rights charges.

(n) Concept: OtherChargesTransmissionOfElectricityByOthers

Transmission service request non-refundable fees.

(o) Concept: OtherChargesTransmissionOfElectricityByOthers

Wind integration and generator imbalance charges.

(p) Concept: OtherChargesTransmissionOfElectricityByOthers

BPA - Prior Period Adjustments:

$	(58)	Loss return settlement
$	(5,054)	BPA Firm - Montana Intertie
$	97,345	Spin Reserve Requirement
$	63,605	Supplemental Reserve Requirement
$	7,006	Non-firm purchases wheeling
$	(46,254)	Capacity Rights
$	(261,370)	Wind Intergration
$	**(144,780)**	**Total**

(q) Concept: OtherChargesTransmissionOfElectricityByOthers

Avista EIM pass-through charges.

(r) Concept: OtherChargesTransmissionOfElectricityByOthers

Reimbursement from Dynasty Power for use of PSE capacity on Bonneville Power Administration lines.

(s) Concept: OtherChargesTransmissionOfElectricityByOthers

Use of facilities charges.

(t) Concept: OtherChargesTransmissionOfElectricityByOthers

Use of transmission facilities charges.

(u) Concept: OtherChargesTransmissionOfElectricityByOthers

Reimbursement from Iberdrola Renewables for use of PSE capacity on Bonneville Power Administration lines.

(v) Concept: OtherChargesTransmissionOfElectricityByOthers

Actual cost capacity charges.

(w) Concept: OtherChargesTransmissionOfElectricityByOthers

Wind integration charges.

(x) Concept: OtherChargesTransmissionOfElectricityByOthers

Adjustment of prior period wind integration charges.

(y) Concept: OtherChargesTransmissionOfElectricityByOthers

Reimbursement from Morgan Stanley Capital Group for use of PSE capacity on Bonneville Power Administration lines.

(z) Concept: OtherChargesTransmissionOfElectricityByOthers

Ancillary services.

(aa) Concept: OtherChargesTransmissionOfElectricityByOthers

Ancillary services.

(ab) Concept: OtherChargesTransmissionOfElectricityByOthers

Northwestern EIM pass-through charges.

(ac) Concept: OtherChargesTransmissionOfElectricityByOthers

Use of transmission facilities charges.

(ad) Concept: OtherChargesTransmissionOfElectricityByOthers

Prior period adjustment of Northwestern EIM pass-through charges, use of transmission facilities charges and NF transmission charges.

(ae) Concept: OtherChargesTransmissionOfElectricityByOthers

Prepay Amortization charge for Seattle City Light.

(af) Concept: OtherChargesTransmissionOfElectricityByOthers

Reimbursement from Shell Energy for use of PSE capacity on Bonneville Power Administration lines.

(ag) Concept: OtherChargesTransmissionOfElectricityByOthers
Premium Amortization.
(ah) Concept: OtherChargesTransmissionOfElectricityByOthers
Reimbursement from The Energy Authority for use of PSE capacity on Bonneville Power Administration lines.
(ai) Concept: OtherChargesTransmissionOfElectricityByOthers
Ancillary services - reserves.
(aj) Concept: OtherChargesTransmissionOfElectricityByOthers
Reimbursement from TransAlta Energy Marketing for use of PSE capacity on Bonneville Power Administration lines.
(ak) Concept: OtherChargesTransmissionOfElectricityByOthers
Whatcom Co PUD inter-connection loss.
(al) Concept: OtherChargesTransmissionOfElectricityByOthers
Whatcom Co PUD inter-connection loss prior period adjustments.
(am) Concept: OtherChargesTransmissionOfElectricityByOthers
Idaho Power EIM Pass-through charges
(an) Concept: OtherChargesTransmissionOfElectricityByOthers
Reimbursement from Conoco for use of PSE capacity on Bonneville Power Administration lines.
(ao) Concept: OtherChargesTransmissionOfElectricityByOthers
Reimbursement from EDF Trading for use of PSE capacity on Bonneville Power Administration lines.
(ap) Concept: OtherChargesTransmissionOfElectricityByOthers
EIM Application Fee PSEM to PSEI
(aq) Concept: OtherChargesTransmissionOfElectricityByOthers
Prior period adjustment of Portland General Electric - Rate case refund 2022
(ar) Concept: OtherChargesTransmissionOfElectricityByOthers
Purchased from Snohomish County for use of Bonneville Power Administration lines & Beverly Park annual use of facilities charge
(as) Concept: OtherChargesTransmissionOfElectricityByOthers
Reimbursement from Tacoma Power for use of PSE capacity on Bonneville Power Administration lines.
(at) Concept: OtherChargesTransmissionOfElectricityByOthers
Reimbursement from Vitol for use of PSE capacity on Bonneville Power Administration lines.
(au) Concept: OtherChargesTransmissionOfElectricityByOthers
Purchased from Seattle City Light for use of Bonneville Power Administration lines

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,071,647
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Western Electric Coordinator Council Dues	8,000
7	Board of Director Fees and Expenses	650,735
8	Other Membership Dues	739,868
9	Treasury Fees & Expenses	101,017
10	Misc General Expense - Electric	6,616,756
11	State/Fed Govt Related Industry Expenses	(630)
46	TOTAL	9,187,393

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

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 B 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 of 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					
2	Steam Production Plant	39,706,645	147,663	11,541,190		51,395,498
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	20,380,239		1,237,952		21,618,191
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	91,335,455	3,217,133			94,552,588
7	Transmission Plant	37,267,959	67,565			37,335,524
8	Distribution Plant	171,427,092	226,883			171,653,975
9	Regional Transmission and Market Operation					
10	General Plant	15,618,734				15,618,734
11	Common Plant-Electric	18,014,285	105,177	44,095,861		62,215,323
12	TOTAL	393,750,409	3,764,421	56,875,003		454,389,833

B. Basis for Amortization Charges

Line No.	C. Factors Used in Estimating Depreciation Charges						
	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)
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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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.
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 columns (f), (g), and (h), expenses incurred during the 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						
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 Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	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)
1	WUTC Filing Fee	10,763,877		10,763,877		Electric	928	10,763,877				
2	Federal fees:											
3	Upper & Lower Baker Project	2,175,933		2,175,933		Electric	928	2,175,933				
4	Snoqualmie 1 & 2 Project	190,693		190,693		Electric	928	190,693				
5	FERC Regulatory Comm Trading	1,266,187		1,266,187		Electric	928	1,266,187				
6	Other Charges:											
7	FERC Regulatory Legal Fees		522,705	522,705		Electric	928	522,705				
8	State Regulatory Legal Fees		512,787	512,787		Electric	928	512,787				
9	Transmission Rate Case		54,842	54,842		Electric	928	54,842				
10	General Rate Case Legal Fees		558,940	558,940		Electric	928	558,940				
46	TOTAL	14,396,690	1,649,274	16,045,964				16,045,964				

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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 and 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 and 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 and 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 and D Performed Externally:
     1. Research Support to the electrical Research Council or the Electric Power Research Institute
     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 and 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 and 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 and 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 and 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.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	Note: No R&D Activity for 2023						

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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	27,351,096		
4	Transmission	8,264,727		
5	Regional Market			
6	Distribution	30,436,062		
7	Customer Accounts	10,042,836		
8	Customer Service and Informational	2,377,648		
9	Sales	834,733		
10	Administrative and General	42,501,370		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	121,808,472		
12	Maintenance			
13	Production	5,284,488		
14	Transmission	2,233,833		
15	Regional Market			
16	Distribution	10,369,106		
17	Administrative and General	46,045		
18	TOTAL Maintenance (Total of lines 13 thru 17)	17,933,472		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	32,635,584		
21	Transmission (Enter Total of lines 4 and 14)	10,498,560		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	40,805,168		
24	Customer Accounts (Transcribe from line 7)	10,042,836		
25	Customer Service and Informational (Transcribe from line 8)	2,377,648		
26	Sales (Transcribe from line 9)	834,733		
27	Administrative and General (Enter Total of lines 10 and 17)	42,547,415		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	139,741,944	1,183,428	140,925,372
29	Gas			
30	Operation			
31	Production - Manufactured Gas	136,885		
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply	3,296,815		
34	Storage, LNG Terminaling and Processing	1,171,360		
35	Transmission			
36	Distribution	22,638,924		
37	Customer Accounts	7,250,478		
38	Customer Service and Informational	1,274,982		
39	Sales	(68,839)		
40	Administrative and General	18,017,462		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	53,718,067		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	408,617		
47	Transmission			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
48	Distribution	6,883,345		
49	Administrative and General	64,127		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	7,356,089		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	136,885		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	3,296,815		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	1,579,977		
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	29,522,269		
58	Customer Accounts (Line 37)	7,250,478		
59	Customer Service and Informational (Line 38)	1,274,982		
60	Sales (Line 39)	(68,839)		
61	Administrative and General (Lines 40 and 49)	18,081,589		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	61,074,156	517,217	61,591,373
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	200,816,100	1,700,645	202,516,745
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	98,923,472	837,749	99,761,221
69	Gas Plant	34,648,077	293,423	34,941,500
70	Other (provide details in footnote):	62,974,205	533,307	63,507,512
71	TOTAL Construction (Total of lines 68 thru 70)	196,545,754	1,664,479	198,210,233
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,792,636	23,650	2,816,286
74	Gas Plant	2,698,739	22,855	2,721,594
75	Other (provide details in footnote):	368,944	3,124	372,068
76	TOTAL Plant Removal (Total of lines 73 thru 75)	5,860,319	49,629	5,909,948
77	Other Accounts (Specify, provide details in footnote):			
78	[(a)] Other Accounts (Specify, provide details in footnote):	29,561,888	250,350	29,812,238
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95	TOTAL Other Accounts	29,561,888	250,350	29,812,238
96	TOTAL SALARIES AND WAGES	432,784,061	3,665,103	436,449,164

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: SalariesAndWagesOtherAccountsDescription

Description	Direct Payroll Distribution (b)	Allocation of Payroll Charged to Clearing Accounts (c)	Total (d) (Col-7 + Col8)
121 Non Utility Property	(679)	(6)	(685)
163 Store Expense	5,127,298	43,421	5,170,719
182 Regulatory Asset	16,667,084	141,148	16,808,232
185 Temporary Facilities	14,650	124	14,774
149 Misc. Deferred Debits	1,734,325	14,687	1,749,012
181 Misc. Deferred Debits	564	5	569
186 Misc. Deferred Debits	3,271,318	27,704	3,299,022
Misc. 400 Accounts	2,723,173	23,062	2,746,235
143 Accts Receivable Misc.	—	—	—
Prelim Survey OG 183	19,016	161	19,177
RMA 184 Orders - allocated OG 184	—	—	—
Misc. 200 Accounts	5,139	44	5,183
Jackson Prairie Joint Venture - Capital - PSE Share	—	—	—
Jackson Prairie Joint Venture - Expense - PSE Share	—	—	—
TOTAL Other Accounts	29,561,888	250,350	29,812,238

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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 Electric 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 the order of the Commission or other authorization.

1 & 2 Common Plant and Accumulated Provision for Depreciation:

ACCOUNT	DESCRIPTION	BOOK VALUE 12/31/2023	ACCUMULATED PROVISION FOR DEPR & AMORT
C302	Franchises	485,094	240,796
C303	Software Development	454,286,567	231,086,873
C389	Land and Land Rights	53,483,328	3,370,490
C390	Structures and Improvements	217,440,489	97,746,987
C391	Office Furniture and Equipment	97,643,186	18,323,231
C392	Transportation Equipment	1,469,778	2,028,380
C393	Stores Equipment	92,576	49,624
C394	Tools/Shop/Garage Equipment	1,511,886	1,236,614
C396	Power Operated Equipment	578,046	311,350
C397	Communication Equipment	143,853,237	48,309,347
C398	Miscellaneous Equipment	632,323	2,818,930
C399	Other Tangible Property	1,258,506	484,283
Total	Common Plant in Service	972,735,016	406,006,905

Common plant balances are not allocated to electric or gas departments.

3. Common expense allocated to Electric and Gas Department:

Account	Description	Total Allocated	Allocated to Electric	Allocated to Gas	Basis
403	Depreciation	27,435,706	18,014,284	9,421,421	(D)
404	Amortization of LTD Term Plant	72,002,924	47,277,120	24,725,804	(D)
901	Customer Accounts and Collection Supervision	309,281	179,971	129,310	(A)
902	Meter Reading Expense	2,392,519	1,500,109	892,410	(B)
903	Customer Records and Collections	29,156,913	16,966,408	12,190,505	(A)
904	Uncollectible Accounts	(159,506)	(104,731)	(54,774)	(D)
908	Customer Assistance	733,683	426,930	306,753	(A)
909	Information and Instructional Advertising	1,573,468	915,601	657,867	(A)
910	Miscellaneous Customer Services and Information	376	219	157	(A)
912	Common Sales	(303,450)	(176,578)	(126,872)	(A)
920	Administrative and General Salaries	109,700,235	72,029,174	37,671,061	(D)
921	Office Supplies & Expense	2,927,643	1,922,290	1,005,352	(D)
922	Administrative Expense Transferred	(49,292,814)	(32,365,661)	(16,927,152)	(D)
923	Outside Services Employed	24,774,842	16,267,161	8,507,681	(D)
924	Property Insurance	(281,053)	(166,074)	(114,979)	(C)
925	Injuries & Damages	9,865,585	5,740,784	4,124,801	(A)
928	Regulatory Commission	985,716	647,221	338,495	(D)
930.1	Common Gen Advertising Exp	1,085	712	372	(D)
930.2	Miscellaneous General Expense	12,386,772	8,133,155	4,253,618	(D)
931	Rents	7,435,115	4,881,897	2,553,219	(D)
935	Maintenance of General Plant	26,031,471	17,092,264	8,939,207	(D)
Total Expense		277,676,511	179,182,255	98,494,256	

(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: 65.66%, and Gas: 34.34%

4. Docket UE-960195 of the Washington Utilities and Transportation Commission, dated February 5, 1997.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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)	21,829,171	12,307,193	12,762,052	[a]14,662,438
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(20,690,879)	(7,117,707)	(11,477,071)	[b](13,227,174)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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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)
46	TOTAL	1,138,292	5,189,486	1,284,981	1,435,264
		Page 397			

FOOTNOTE DATA

(a) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

	Q1, 2023	Q2, 2023	Q3, 2023	Q4, 2023	YTD 2023
EIM Purchases	$ 21,278,658	$ 8,214,208	$ 10,642,307	$ 13,066,120	$ 53,201,293
Intertie Purchases	550,513	4,092,985	2,119,745	1,596,319	8,359,562
Total by Quarter	**$ 21,829,171**	**$ 12,307,193**	**$ 12,762,052**	**$ 14,662,439**	**$ 61,560,855**

(b) Concept: IsoOrRtoSettlementsEnergyNetSales

	Q1, 2023	Q2, 2023	Q3, 2023	Q4, 2023	YTD 2023
EIM Purchases	$ (19,679,151)	$ (7,046,035)	$ (11,349,064)	$ (12,989,607)	$ (51,063,858)
Intertie Purchases	(1,011,728)	(71,672)	(128,007)	(237,567)	(1,448,974)
Total by Quarter	**$ (20,690,879)**	**$ (7,117,707)**	**$ (11,477,071)**	**$ (13,227,174)**	**$ (52,512,832)**

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) 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.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	[a]0			[b]115,237	MW	10,797,917
2	Reactive Supply and Voltage	[c]0			[d]28,680	MW	183,846
3	Regulation and Frequency Response	0	MWH		[e]5,833	MW	2,284,466
4	Energy Imbalance	(29,872)	MWH	2,669,825	(74,129)	MWh	(157,962)
5	Operating Reserve - Spinning	3,263,548	MWH	1,206,439	[f]6,659	MW	936,519
6	Operating Reserve - Supplement	3,263,548	MWH	802,612	[g]6,659	MW	911,224
7	Other	[h]78060	MW	1,069,085	[i]73,103	MWh	(4,436,427)
8	Total (Lines 1 thru 7)	6,575,284		5,747,961	162,042		10,519,583

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits

Number of Units	Unit of measure	Dollars
163,230	MW	$ 27,874,471
46,924	MWh	42,132
		$ 27,916,603

(b) Concept: AncillaryServicesSoldNumberOfUnits

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.)

(c) Concept: AncillaryServicesPurchasedNumberOfUnits

Number of Units	Unit of measure	Dollars
87,249	MW	$ 100,163
46,008	MWh	—
		$ 100,163

The units include reactive supply and voltage received from Bonneville Power Administration for which the rate is currently zero.

(d) Concept: AncillaryServicesSoldNumberOfUnits

Units for column e lines 1, 2, 3, 5, and 6 have been calculated to a normalizedMW/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.)

(e) Concept: AncillaryServicesSoldNumberOfUnits

Sales can be broken down as follows:Schedule 3, Units: 4,493 MW, Dollars: $576,728Schedule 13, Units: 1,340 MW, Dollars: $1,707,738Units for column e lines 1, 2, 3, 5, and 6 have been calculated to a normalizedMW/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.)

(f) Concept: AncillaryServicesSoldNumberOfUnits

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.)

(g) Concept: AncillaryServicesSoldNumberOfUnits

Units for column e lines 1, 2, 3, 5, and 6 have been calculated to a normalized W/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.)

(h) Concept: AncillaryServicesPurchasedNumberOfUnits

Schedule 9 Generator Imbalance is reported in "Other" sales.

(i) Concept: AncillaryServicesSoldNumberOfUnits

Schedule 9 Generator Imbalance is reported in "Other" sales.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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.

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)
	NAME OF SYSTEM: 1) Puget Sound Energy, Inc.									
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									
	NAME OF SYSTEM: 1) WA Area Facilities (Page 400)									
1	January	5,151	30	9	[(a)]4,202	354	581	14	3,541	[(m)]205
2	February	5,133	24	8	[(b)]4,176	361	581	15	3,945	[(n)]132
3	March	4,737	1	8	[(c)]3,810	333	581	13	1,855	[(o)]228
4	Total for Quarter 1				12,188	1,048	1,743	42	9,341	565
5	April	4,241	3	9	[(d)]3,349	298	581	13	2,154	[(p)]480
6	May	4,064	15	18	[(e)]3,197	270	581	16	3,884	[(q)]361
7	June	3,914	7	18	[(f)]3,007	312	581	14	1,868	[(r)]489
8	Total for Quarter 2				9,553	880	1,743	43	7,906	1,330
9	July	4,191	5	18	[(g)]3,280	315	581	15	3,379	[(s)]283
10	August	4,660	15	18	[(h)]3,733	330	581	16	2,484	[(t)]284
11	September	3,652	2	18	[(i)]2,764	295	581	12	2,580	[(u)]503
12	Total for Quarter 3				9,777	940	1,743	43	8,443	1,070
13	October	4,404	30	9	[(j)]3,492	316	581	15	2,173	[(v)]128
14	November	4,790	28	9	[(k)]3,846	349	581	14	1,856	[(w)]225
15	December	4,501	9	17	[(l)]3,573	334	581	13	1,869	[(x)]245
16	Total for Quarter 4				10,911	999	1,743	42	5,898	598
17	Total				42,429	3,867	6,972	170	31,588	3,563
	NAME OF SYSTEM: 2) Southern Intertie (Page 400)									
1	January	700					400	300	6	
2	February	700					400	300	6	
3	March	700					400	300	6	
4	Total for Quarter 1				0	0	1,200	900	18	0
5	April	700					400	300	0	

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)
6	May	700					400	300	6	
7	June	700					400	300	6	
8	Total for Quarter 2				0	0	1,200	900	12	0
9	July	700					400	300	6	
10	August	700					400	300	6	
11	September	700					400	300	6	
12	Total for Quarter 3				0	0	1,200	900	18	0
13	October	700					400	300	6	
14	November	700					400	300	6	
15	December	700					400	300	6	
16	Total for Quarter 4				0	0	1,200	900	18	0
17	Total				0	0	4,800	3,600	66	0
	NAME OF SYSTEM: 3) Colstrip (Page 400)									
1	January	713					713			
2	February	713					713			
3	March	713					713			
4	Total for Quarter 1				0	0	2,139	0	0	0
5	April	713					713			
6	May	713					713			
7	June	713					713			
8	Total for Quarter 2				0	0	2,139	0	0	0
9	July	713					713			
10	August	713					713			
11	September	713					713			
12	Total for Quarter 3				0	0	2,139	0	0	0
13	October	746					746			
14	November	746					746			
15	December	746					746			
16	Total for Quarter 4				0	0	2,238	0	0	0
17	Total				0	0	8,655	0	0	0
	NAME OF SYSTEM: Total (Page 400)									
1	January	6,564			4,202	354	1,694	314	3,547	205
2	February	6,546			4,176	361	1,694	315	3,951	132
3	March	6,150			3,810	333	1,694	313	1,861	228
4	Total for Quarter 1				12,188	1,048	5,082	942	9,359	565
5	April	5,654			3,349	298	1,694	313	2,154	480
6	May	5,477			3,197	270	1,694	316	3,890	361
7	June	5,327			3,007	312	1,694	314	1,874	489
8	Total for Quarter 2				9,553	880	5,082	943	7,918	1,330
9	July	5,604			3,280	315	1,694	315	3,385	283
10	August	6,073			3,733	330	1,694	316	2,490	284
11	September	5,065			2,764	295	1,694	312	2,586	503
12	Total for Quarter 3				9,777	940	5,082	943	8,461	1,070
13	October	5,850			3,492	316	1,727	315	2,179	128
14	November	6,236			3,846	349	1,727	314	1,862	225
15	December	5,947			3,573	334	1,727	313	1,875	245
16	Total for Quarter 4				10,911	999	5,181	942	5,916	598
17	Total				42,429	3,867	20,427	3,770	31,654	3,563

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: FirmNetworkServiceForSelf

Previously reported Quarterly totals in Q1 - Q3 2022 for Firm Network Service for Self (e) and Firm Network Service for Others (f) have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission for the day and hour of the monthly peak.

(b) Concept: FirmNetworkServiceForSelf

Previously reported Quarterly totals in Q1 - Q3 2022 for Firm Network Service for Self (e) and Firm Network Service for Others (f) have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission for the day and hour of the monthly peak.

(c) Concept: FirmNetworkServiceForSelf

Previously reported Quarterly totals in Q1 - Q3 2022 for Firm Network Service for Self (e) and Firm Network Service for Others (f) have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission for the day and hour of the monthly peak.

(d) Concept: FirmNetworkServiceForSelf

Previously reported Quarterly totals in Q1 - Q3 2022 for Firm Network Service for Self (e) and Firm Network Service for Others (f) have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission for the day and hour of the monthly peak.

(e) Concept: FirmNetworkServiceForSelf

Previously reported Quarterly totals in Q1 - Q3 2022 for Firm Network Service for Self (e) and Firm Network Service for Others (f) have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission for the day and hour of the monthly peak.

(f) Concept: FirmNetworkServiceForSelf

Previously reported Quarterly totals in Q1 - Q3 2022 for Firm Network Service for Self (e) and Firm Network Service for Others (f) have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission for the day and hour of the monthly peak.

(g) Concept: FirmNetworkServiceForSelf

Previously reported Quarterly totals in Q1 - Q3 2022 for Firm Network Service for Self (e) and Firm Network Service for Others (f) have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission for the day and hour of the monthly peak.

(h) Concept: FirmNetworkServiceForSelf

Previously reported Quarterly totals in Q1 - Q3 2022 for Firm Network Service for Self (e) and Firm Network Service for Others (f) have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission for the day and hour of the monthly peak.

(i) Concept: FirmNetworkServiceForSelf

Previously reported Quarterly totals in Q1 - Q3 2022 for Firm Network Service for Self (e) and Firm Network Service for Others (f) have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission for the day and hour of the monthly peak.

(j) Concept: FirmNetworkServiceForSelf

Previously reported Quarterly totals in Q1 - Q3 2022 for Firm Network Service for Self (e) and Firm Network Service for Others (f) have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission for the day and hour of the monthly peak.

(k) Concept: FirmNetworkServiceForSelf

Previously reported Quarterly totals in Q1 - Q3 2022 for Firm Network Service for Self (e) and Firm Network Service for Others (f) have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission for the day and hour of the monthly peak.

(l) Concept: FirmNetworkServiceForSelf

Previously reported Quarterly totals in Q1 - Q3 2022 for Firm Network Service for Self (e) and Firm Network Service for Others (f) have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission have been updated to reflect corrected meter data. Q4 data corrected prior to Q4 form submission for the day and hour of the monthly peak.

(m) Concept: OtherService

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.

(n) Concept: OtherService

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.

(o) Concept: OtherService

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.

(p) Concept: OtherService

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.

(q) Concept: OtherService

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.

(r) Concept: OtherService

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.

(s) Concept: OtherService

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.

(t) Concept: OtherService

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.

(u) Concept: OtherService

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.

(v) Concept: OtherService

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.

(w) Concept: OtherService

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.

(x) Concept: OtherService

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.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import 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)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-04-16	Year/Period of Report End of: 2023/ 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)	21,165,762
3	Steam	5,223,967	23	Requirements Sales for Resale (See instruction 4, page 311.)	6,700
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	9,026,924
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage	699,907	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	23,211
7	Other	8,970,507	27	Total Energy Losses	1,090,701
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	14,894,381	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	31,313,298
10	Purchases (other than for Energy Storage)	16,603,754			
10.1	Purchases for Energy Storage				
11	Power Exchanges:				
12	Received	439,126			
13	Delivered	623,963			
14	Net Exchanges (Line 12 minus line 13)	(184,837)			
15	Transmission For Other (Wheeling)				
16	Received	9,067,790			
17	Delivered	9,067,790			
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	31,313,298			

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

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).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 1) Puget Sound Energy, Inc.					
29	January	[(a)]2,858,519	636,389	4,329	30	9
30	February	2,622,904	557,943	4,308	24	8
31	March	3,021,617	917,163	3,925	1	8
32	April	2,396,818	597,379	3,411	3	9
33	May	1,830,105	208,237	3,276	15	18
34	June	2,008,994	470,676	3,090	7	19
35	July	2,687,590	1,007,385	3,365	5	19
36	August	2,698,254	961,593	3,853	16	18
37	September	2,502,675	969,452	2,834	2	18
38	October	2,243,480	496,396	3,585	30	9
39	November	2,896,189	846,838	3,954	28	9
40	December	3,130,667	958,009	3,704	9	17
41	Total	30,897,812	8,627,460			

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: EnergyActivity

NAME OF SYSTEM: **Point Roberts Transfer Point**

2022

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)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
1	January	2,421	0	5.0	30	0900
2	February	2,314	0	5.8	24	0800
3	March	2,115	0	4.3	1	0800
4	**Total**	**6,850**	**0**			
5	April	1,747	0	3.6	2	0900
6	May	1,163	0	2.4	6	0900
7	June	1,068	0	2.2	10	1400
8	**Total**	**3,978**	**0**			
9	July	1,167	0	2.2	2	1900
10	August	1,179	0	2.3	6	1800
11	September	1,112	0	2.3	30	1900
12	**Total**	**3,458**	**0**			
13	October	1,532	0	4.1	28	0800
14	November	2,058	0	4.2	29	0900
15	December	2,235	0	4.5	9	1500
16	**Total**	**5,825**	**0**			
17	**Yr Total**	**20,111**	**0**			

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

Steam Electric Generating Plant Statistics

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 Mcf.
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.
9. Items under Cost of Plant are based on USofA 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.

Line No.	Item (a)	Plant Name: Colstrip 3 & 4	Plant Name: Encogen	Plant Name: Ferndale	Plant Name: [a] Frederickson	Plant Name: Frederickson 1	Plant Name: [b] Fredonia 1&2	Plant Name: [c] Fredonia 3&4	Plant Name: Goldendale	Plant Name: Hopkins Ridge
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Combined Cycle	Combined Cycle	Gas Turbine	Combined Cycle	Gas Turbine	Gas Turbine	Combined Cycle	Wind Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor	Outdoor	Outdoor	Outdoor	Outdoor	Outdoor	Outdoor	Outdoor	Outdoor
3	Year Originally Constructed	1984	1993	1994	1981	2002	1984	2001	2004	2005
4	Year Last Unit was Installed	1986	1993	1994	1981	2002	1984	2001	2004	2008
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	[e]370.0	165.0	253.0	149.0	[f]136.0	207.0	107.0	315.0	157.0
6	Net Peak Demand on Plant - MW (60 minutes)	374.4	166.2	274.4	153.1	133.6	212.0	117.8	313.4	152.2
7	Plant Hours Connected to Load	8,758	6,295	6,523	2,386	7,379	5,231	3,277	7,773	8,658
8	Net Continuous Plant Capability (Megawatts)									
9	When Not Limited by Condenser Water	370	165	253	149	136	207	107	315	
10	When Limited by Condenser Water	0	0	0	0	0	0	0	0	
11	Average Number of Employees	[g]0	14	[h]0	6	[i]0	5	4	17	6
12	Net Generation, Exclusive of Plant Use - kWh	2,673,671,000	903,027,000	1,529,332,001	159,586,760	909,289,677	679,146,600	287,933,100	2,212,693,000	328,736,818
13	Cost of Plant: Land and Land Rights	2,788,745	1,051,000		785,528	699,814	1,502,988		1,288,140	
14	Structures and Improvements	129,794,061	9,241,352	6,594,636	3,569,470	6,213,352	4,018,224	1,610,745	37,212,381	3,351,299
15	Equipment Costs	402,970,202	155,767,042	145,747,947	38,706,418	66,300,807	85,275,033	64,409,492	301,824,834	170,993,459
16	Asset Retirement Costs			1,030,922		443,797				12,455,466
17	Total cost (total 13 thru 20)	535,553,008	166,059,394	153,373,505	43,061,416	73,657,770	90,796,245	66,020,237	340,325,355	186,800,224
18	Cost per KW of Installed Capacity (line 17/5) Including	1,447	1,006	606	289	542	439	617	1,080	1,190
19	Production Expenses: Oper, Supv, & Engr	86,064	314,188	651,671	89,929	2,013,338	299,176	43,945	385,394	360,716
20	Fuel	60,636,604	37,136,519	66,871,435	9,824,471	31,328,456	35,116,280	12,824,299	72,447,643	
21	Coolants and Water (Nuclear Plants Only)									
22	Steam Expenses	2,892,900	178,830	1,249,578		41,786			1,888,391	
23	Steam From Other Sources									
24	Steam Transferred (Cr)									
25	Electric Expenses	(328,666)	3,854,135	3,229,200	964,560	1,281,592	2,392,468	8,073	3,384,260	635,832
26	Misc Steam (or Nuclear) Power Expenses	7,337,425				32,628				
27	Rents									832,160
28	Allowances									
29	Maintenance Supervision and Engineering	516,505	6,171		6,171	187,091	6,171	6,171	6,171	108,691
30	Maintenance of Structures	1,317,272	20,410	14,398	155,744	24,293	77,900		140,335	46,924
31	Maintenance of Boiler (or reactor) Plant	8,655,753	563,980	994,701		380,297			605,633	
32	Maintenance of Electric Plant	2,895,667	2,150,828	3,062,567	626,620	838,757	2,601,076	191,451	3,291,893	4,389,103
33	Maintenance of Misc Steam (or Nuclear) Plant	819,160	55,258	327,701		67,958			91,591	
34	Total Production Expenses	84,828,684	44,280,318	76,401,251	11,667,495	36,196,197	40,493,071	13,073,939	82,241,311	6,373,426
35	Expenses per Net kWh	0.0317	0.0490	0.0500	0.0731	0.0398	0.0596	0.0454	0.0372	0.0194

Line No.	Item (a)	Plant Name: Lower Snake River	Plant Name: Mint Farm	Plant Name: Sumas	Plant Name: (d) Whitehorn	Plant Name: Wild Horse
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Wind Turbine	Combined Cycle	Combined Cycle	Gas Turbine	Wind Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor	Outdoor	Outdoor	Outdoor	Outdoor
3	Year Originally Constructed	2012	2007	1993	1981	2006
4	Year Last Unit was Installed	2012	2007	1993	1981	2009
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	343.0	320.0	127.0	149.0	273.0
6	Net Peak Demand on Plant - MW (60 minutes)	338.6	329.8	131.8	146.2	261.4
7	Plant Hours Connected to Load	7,913	7,039	7,029	4,983	8,435
8	Net Continuous Plant Capability (Megawatts)					
9	When Not Limited by Condenser Water		320	127	149	
10	When Limited by Condenser Water		0	0	0	
11	Average Number of Employees	5	17	13	5	11
12	Net Generation, Exclusive of Plant Use - kWh	711,413,417	1,989,583,200	834,872,700	448,958,000	525,311,808
13	Cost of Plant: Land and Land Rights	203,682	1,194,000	795,165	364,590	8,131,854
14	Structures and Improvements	31,393,624	12,858,413	5,697,005	2,675,813	14,993,617
15	Equipment Costs	648,549,937	114,012,319	78,088,433	37,153,461	409,038,243
16	Asset Retirement Costs	17,350,201				22,037,384
17	Total cost (total 13 thru 20)	697,497,444	128,064,732	84,580,603	40,193,864	454,201,098
18	Cost per KW of Installed Capacity (line 17/5) Including	2,034	400	666	270	1,664
19	Production Expenses: Oper, Supv, & Engr	422,569	425,813	314,433	65,516	431,371
20	Fuel		74,324,406	32,381,524	24,386,270	
21	Coolants and Water (Nuclear Plants Only)					
22	Steam Expenses		279,580	398,474		
23	Steam From Other Sources					
24	Steam Transferred (Cr)					
25	Electric Expenses	883,200	2,924,569	3,011,849	839,746	666,250
26	Misc Steam (or Nuclear) Power Expenses					
27	Rents	3,589,340				2,386,604
28	Allowances					
29	Maintenance Supervision and Engineering	79,306	6,557	61,610	6,171	129,525
30	Maintenance of Structures	86,090	54,335	10,094	82,527	23,153
31	Maintenance of Boiler (or reactor) Plant		788,899	623,885		
32	Maintenance of Electric Plant	1,044,706	3,155,837	1,001,815	481,040	7,441,286
33	Maintenance of Misc Steam (or Nuclear) Plant		95,347	2,153		
34	Total Production Expenses	6,105,211	82,055,343	37,805,837	25,861,270	11,078,189
35	Expenses per Net kWh	0.0086	0.0412	0.0453	0.0576	0.0211

35	**Plant Name**	Colstrip 3 & 4	Encogen	Encogen	Ferndale	Ferndale	Frederickson	Frederickson	Frederickson 1	Fredonia 1&2	Fredonia 1&2	Fredonia 3&4
36	Fuel Kind	Coal	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Gas	Oil	Gas
37	Fuel Unit	T	Mcf	bbl	Mcf	bbl	Mcf	bbl	Mcf	Mcf	bbl	Mcf
38	Quantity (Units) of Fuel Burned	1,663,977	7,257,585		11,535,707	6,863	2,069,948	2,024	5,927,486	7,626,171	5	2,578,902
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8,614	1,100,497		1,100,497	138,683	1,100,497	138,892	1,100,497	1,100,497	137,025	1,100,497
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	33.545	5.117		5.710	159.003	4.629	293.155	5.285	4.605	155.338	4.832
41	Average Cost of Fuel per Unit Burned	36.441	5.117		5.710	145.456	4.629	120.138	5.285	4.605	124.525	4.832
42	Average Cost of Fuel Burned per Million BTU	2.115	4.650		5.189	24.972	4.206	20.595	4.803	4.184	21.638	4.390
43	Average Cost of Fuel Burned per kWh Net Gen	0.023	0.041		0.043	0.020	0.060	0.371	0.034	0.052	0.153	0.044
44	Average BTU per kWh Net Generation	10,721.960	8,844.646		8,328.508	7,919.706	14,332.992	18,035.595	7,173.933	12,357.619	7,063.885	9,920.809

35	**Plant Name**	Fredonia 3&4	Goldendale	Mint Farm	Sumas	Whitehorn	Whitehorn
36	Fuel Kind	Oil	Gas	Gas	Gas	Gas	Oil
37	Fuel Unit	bbl	Mcf	Mcf	Mcf	Mcf	bbl
38	Quantity (Units) of Fuel Burned	2,923	13,748,018	13,249,591	6,193,462	5,349,887	265
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	137,025	1,100,497	1,100,497	1,100,497	1,100,497	136,837
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	155.338	5.270	5.610	5.228	4.552	164.929
41	Average Cost of Fuel per Unit Burned	124.513	5.270	5.610	5.228	4.552	132.599
42	Average Cost of Fuel Burned per Million BTU	21.635	4.788	5.097	4.751	4.136	23.072
43	Average Cost of Fuel Burned per kWh Net Gen	0.196	0.033	0.037	0.039	0.054	0.316
44	Average BTU per kWh Net Generation	9,041.714	6,837.667	7,328.741	8,163.985	13,117.035	13,685.737

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: PlantName
Peak load plant.
(b) Concept: PlantName
Peak load plant.
(c) Concept: PlantName
Peak load plant.
(d) Concept: PlantName
Peak load plant.
(e) Concept: InstalledCapacityOfPlant
Jointly owned. Amount represents 25% of rated capacity of 1,480,000 KW.
(f) Concept: InstalledCapacityOfPlant
Jointly owned. Amount represents PSE's 49.85% share.
(g) Concept: PlantAverageNumberOfEmployees
Colstrip is operated by Talen Montana, LLC. There are no PSE employees at the plant.
(h) Concept: PlantAverageNumberOfEmployees
Ferndale is operated by NAES Corporation for Puget Sound Energy.
(i) Concept: PlantAverageNumberOfEmployees
Facility was operated by Atlantic Power Corporation. There are no PSE employees.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

Hydroelectric Generating Plant Statistics

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.
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.

Line No.	Item (a)	FERC Licensed Project No. Plant Name: LOWER BAKER	FERC Licensed Project No. Plant Name: SNOQUALMIE FALLS	FERC Licensed Project No. Plant Name: UPPER BAKER
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional	Conventional
3	Year Originally Constructed	1925	1898	1959
4	Year Last Unit was Installed	2013	2013	1959
5	Total installed cap (Gen name plate Rating in MW)	105.00	54.00	104.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	102	47	110
7	Plant Hours Connect to Load	8,731	8,729	4,248
8	**Net Plant Capability (in megawatts)**			
9	(a) Under Most Favorable Oper Conditions	118	50	110
10	(b) Under the Most Adverse Oper Conditions	83	50	90
11	Average Number of Employees	[(a)]18	16	[(b)]18
12	Net Generation, Exclusive of Plant Use - kWh	262,829,900	166,238,000	270,839,200
13	**Cost of Plant**			
14	Land and Land Rights	8,732,638	554,102	2,001,428
15	Structures and Improvements	46,451,999	116,213,959	16,754,414
16	Reservoirs, Dams, and Waterways	124,251,051	115,733,203	141,336,153
17	Equipment Costs	67,599,951	107,720,699	36,528,280
18	Roads, Railroads, and Bridges	1,588,316	808,565	2,648,182
19	Asset Retirement Costs			
20	Total cost (total 13 thru 20)	248,623,955	341,030,528	199,268,457
21	Cost per KW of Installed Capacity (line 20 / 5)	2,367.8472	6,315.3801	1,916.0429
22	**Production Expenses**			
23	Operation Supervision and Engineering	665,870	340,869	697,900
24	Water for Power			
25	Hydraulic Expenses	1,680,071	492,404	2,007,147
26	Electric Expenses		341,918	
27	Misc Hydraulic Power Generation Expenses	(1,101,528)	995,727	542,761
28	Rents			
29	Maintenance Supervision and Engineering	23,018	36,105	23,018
30	Maintenance of Structures	94,686	270,816	234,101
31	Maintenance of Reservoirs, Dams, and Waterways	55,523	258,199	431,338
32	Maintenance of Electric Plant	161,023	872,325	132,869
33	Maintenance of Misc Hydraulic Plant	2,632,822	480,084	1,245,860
34	Total Production Expenses (total 23 thru 33)	4,211,485	4,088,446	5,314,995
35	Expenses per net kWh	0.0160	0.0246	0.0196

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: PlantAverageNumberOfEmployees
There was a total of 36 full time equivalent employees at Baker. They work at both Upper Baker and Lower Baker so split the total number between the two, 18 for Lower Baker, and 18 for Upper Baker.
(b) Concept: PlantAverageNumberOfEmployees
There was a total of 36 full time equivalent employees at Baker. They work at both Upper Baker and Lower Baker so split the total number between the two, 18 for Lower Baker, and 18 for Upper Baker.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

Pumped Storage Generating Plant Statistics

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 that 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."
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.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
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	0
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)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
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.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)
1	INTERNAL COMBUSTION											
2	Crystal Mountain	1969	2.75	2.7	[a]34,180	2,899,911	1,054,513	62,414	8,861	185,883	Diesel	3,009

Line No.	Generation Type (m)
1	
2	Internal Combustion

FOOTNOTE DATA

(a) Concept: NetGenerationExcludingPlantUse

Generation is in kWh.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a genera ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generator whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Othe Cost Associ with S Genera Pow (Dolla (o)
35	TOTAL			0	0	0	0	0	0	0	0	0	0	0	

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR				
					Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1	Glacier Battery Storage	Distribution	Glacier, Washington	5,418,422		21,999		4,465	
36	TOTAL			5,418,422	0	21,999	0	4,465	0

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
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. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. 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.
5. 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.
6. 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).
7. 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.
8. 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.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	[(a)] 3rd Ac Trans Line								
2	[(b)] Broadview S Y	Townsend A Line	500.00	500.00	SCST	133.40		1	4-795 ACSR
3	[(c)] Broadview S Y	Townsend B Line	500.00	500.00	SCST	133.40		1	4-795 ACSR
4	[(d)] Colstrip 3	Switch Yard	500.00	500.00	SCST	0.40		1	2-2250 ACSR
5	[(e)] Colstrip 4	Switch Yard	500.00	500.00	SCST	0.40		1	2-2250 ACSR
6	[(f)] Colstrip SY	Broadview A Line	500.00	500.00	SCST	112.70		1	4-795 ACSR
7	[(g)] Colstrip SY	Broadview B Line	500.00	500.00	SCST	115.90		1	4-795 ACSR
8	500 Kv Tot								
9	Bpa Covington	Berrydale	230.00	230.00	DCST,SCST	4.06		2	2-1590 ACSS
10	Bpa Covington	White River #2	230.00	230.00	DCST	9.25		1	2-1272 ACSR
11	Bpa Custer	Portal Way	230.00	230.00	WHF	0.06		1	795 ACSR
12	Bpa Maple Valley	Talbot #1	230.00	230.00	SCST	0.18		1	2-1780 ACSR
13	Bpa Maple Valley	Talbot #2	230.00	230.00	SCST	0.15		1	2-1780 ACSR
14	Bpa Monroe	Novelty Hill	230.00	230.00	SCST, DCST	0.27		1	1780 ACSR
15	Bpa Olympia	Saint Clair	230.00	230.00	DCST	3.62		1	1590 ACSS
16	Bpa Shelton	South Bremerton	230.00	230.00	WHF	0.80		1	1590 ACSR
17	Cascade	White River	230.00	230.00	SCST, WHF	68.99		1	1272 ACSR
18	Christopher	O'Brien #4	230.00	230.00	DCST	4.75		1	2-1272 ACSR
19	Colstrip 1	Switch Yard	230.00	230.00	SCST	0.40		1	1272 ACSR
20	Colstrip 2	Switch Yard	230.00	230.00	SCST	0.40		1	1272 ACSR
21	Dodge Junction	Phalen Gulch	230.00	230.00	WHF	5.22		1	2-1272 ACSR
22	[(h)] Freddy/APC	Bpa South Tacoma #1	230.00	230.00	UG CABLE	0.97		1	1750 KCMIL
23	Horse Ranch Tap	Bpa Monroe Snohomish	230.00	230.00	WHF, SCST	3.48		1	1780 ACSR
24	[(i)] North Intertie		230.00	230.00					
25	Phalen Gulch	BPA Central Ferry	230.00	230.00	WHF	2.08		1	2-1590 ACSR
26	Poison Spring	Wind Ridge	230.00	230.00	HF2	4.10		1	1272 ACSR
27	Rocky Reach	Cascade	230.00	230.00	WHF, SCST	57.86		1	1272 ACSR
28	Saint Clair	Bpa South Tacoma	230.00	230.00	DCST	3.62		1	1590 ACSS
29	Sammamish	Bpa Maple Valley #1	230.00	230.00	DCST, SCST	8.14		1	1780 ACSR
30	Sammamish	Novelty Hill #2	230.00	230.00	DCST, SCST	7.91		1	1780 ACSR
31	SCL Bothell	Sammamish	230.00	230.00	WHF	13.28		1	1590 ACSS
32	Sedro Woolley	Bpa Bellingham	230.00	230.00	WHF	0.11		1	1.6" AACTW
33	Sedro Woolley	Horse Ranch	230.00	230.00	SCST	38.95		1	2-795 ACSR
34	Sedro Woolley	March Point	230.00	230.00	SWP, DCST	23.07		1	2-397.5 ACSR
35	Sedro Woolley	SCL Bothell	230.00	230.00	WHF	49.04		1	2-795 ACSR
36	Sedro Woolley Tap		230.00	230.00	WHF	0.17		1	1590 ACSS
37	Talbot	Berrydale #3	230.00	230.00	DCST	15.78		2	2-1590 ACSR
38	Talbot	O'Brien #3	230.00	230.00	DCST	7.22		1	2-1272 ACSR
39	Talbot	Richard Creek #1	230.00	230.00	STEEL	9.00		1	1590 ACSS
40	Talbot	Richard Creek #2	230.00	230.00	STEEL	9.00		1	1590 ACCS
41	Wanapum	Wind Ridge	230.00	230.00	RHES-MOD,PSET	21.11		1	2-1272 ACSR
42	Wild Horse	Poison Spring	230.00	230.00	HF2	4.52		1	1272 ACSR
43	White River	Alderton #5	230.00	230.00	SCST, DCST	8.34		1	1590 ACCS

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
44	[(j)] 230 KV Tot								
45	115 KV Tot					1,671.39			
46	55 KV Tot					77.47			
47	[(k)] ARC as per FAS 143								
36	TOTAL					2,631		42	

Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
1							
2							
3							
4							
5							
6							
7							
8	1,765,339	116,737,709	118,503,048				
9							
10							
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15							
16							
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41							
42							
43							
44	13,788,446	241,014,169	254,802,615				
45	38,090,949	658,460,205	696,551,154				
46	266,423	21,237,318	21,503,741				
47		1,971,179	1,971,179				
36	53,911,157	1,039,420,580	1,093,331,737	13,971,944	11,909,901	338,210	26,220,055

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionLineStartPoint
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.
(b) Concept: TransmissionLineStartPoint
Facilities are jointly owned with NorthWestern Energy, Avista, Portland General Electric, PacifiCorp and Puget Sound Energy. Plant costs and expenses reflect the respondent's share.
(c) Concept: TransmissionLineStartPoint
Facilities are jointly owned with NorthWestern Energy, Avista, Portland General Electric, PacifiCorp and Puget Sound Energy. Plant costs and expenses reflect the respondent's share.
(d) Concept: TransmissionLineStartPoint
Facilities are jointly owned with NorthWestern Energy, Avista, Portland General Electric, PacifiCorp and Puget Sound Energy. Plant costs and expenses reflect the respondent's share.
(e) Concept: TransmissionLineStartPoint
Facilities are jointly owned with NorthWestern Energy, Avista, Portland General Electric, PacifiCorp and Puget Sound Energy. Plant costs and expenses reflect the respondent's share.
(f) Concept: TransmissionLineStartPoint
Facilities are jointly owned with NorthWestern Energy, Avista, Portland General Electric, PacifiCorp and Puget Sound Energy. Plant costs and expenses reflect the respondent's share.
(g) Concept: TransmissionLineStartPoint
Facilities are jointly owned with NorthWestern Energy, Avista, Portland General Electric, PacifiCorp and Puget Sound Energy. Plant costs and expenses reflect the respondent's share.
(h) Concept: TransmissionLineStartPoint
Facilities are jointly owned with APC (Atlantic Power Corporation). Plant cost and expenses reflect the respondent's share.
(i) Concept: TransmissionLineStartPoint
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.
(j) Concept: TransmissionLineStartPoint
Type of support structure is SP-W, WHF, Steel Tower, and single Wood.
(k) Concept: TransmissionLineStartPoint
Asset retirement cost per FAS 143 was added in 2005.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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 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.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Talbot Hill	Richards Creek #1	9	Steel Monopole	10	1	1	1590	[(a)] ACSS 200 DEG.C	Tangent/14.5'	230
2	Talbot Hill	Richards Creek #2	9	Steel Monopole	10	1	1	1590	[(b)] ACSS 200 DEG.C	Tangent/14.5'	230
3	Sammamish	Juanita Tap	5	Wood, Steel, LAM, and FRP	16	1	1	1272	[(c)] ACSR 100 DEG.C	Tangent/7.5'	115
44	TOTAL		23		36	3	3				

Line No.	LINE COST					Construction
	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	(q)
1						
2						
3						
44						

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: ConductorSpecification
Costs are not yet finalized.
(b) Concept: ConductorSpecification
Costs are not yet finalized.
(c) Concept: ConductorSpecification
Costs are not yet finalized.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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).
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.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
1	ALDERTON PIERCE	Transmission		230.00	115.00	13.20	325	1	0
2	BERRYDALE SOUTH KING	Transmission		230.00	115.00	13.20	325	1	0
3	BPA BELLINGHAM	Transmission		230.00	115.00	13.20	325	1	0
4	CASCADE KITTITAS 1	Transmission		230.00	115.00	34.50	50	1	0
5	CASCADE KITTITAS 2	Transmission		230.00	34.50	0.00	50	1	0
6	DODGE JUNCTION GARFIELD	Transmission		230.00	34.50	0.00	200	1	0
7	FREDONIA SKAGIT	Transmission		230.00	13.20	0.00	210	2	0
8	GOLDENDALE GOLDENDALE	Transmission		230.00	18.00	13.80	365	1	0
9	MARCH POINT SKAGIT	Transmission		230.00	115.00	13.20	325	1	0
10	NOVELTY HILL NORTH KING	Transmission		230.00	115.00	13.20	325	1	0
11	O'BRIEN SOUTH KING	Transmission		230.00	115.00	13.20	650	2	1
12	MINT FARM LONGVIEW 1	Transmission		230.00	18.00	0.00	215	1	0
13	MINT FARM LONGVIEW 2	Transmission		230.00	13.80	0.00	160	1	0
14	PHALEN GULCH GARFIELD	Transmission		230.00	34.50	0.00	200	1	0
15	PORTAL WAY WHATCOM	Transmission		230.00	115.00	13.20	325	1	0
16	SAMMAMISH NORTH KING	Transmission		230.00	115.00	13.20	650	2	0
17	SEDRO WOOLLEY SKAGIT	Transmission		230.00	115.00	13.20	650	2	0
18	SOUTH BREMERTON SOUTH PENNISULA	Transmission		230.00	115.00	13.20	325	1	0
19	ST CLAIR THURSTON	Transmission		230.00	115.00	13.20	325	1	0
20	TALBOT HILL CENTRAL KING	Transmission		230.00	115.00	13.20	650	2	0
21	TONO THURSTON	Transmission		525.00	115.00	13.20	533	3	0
22	WHITE RIVER TRANSM. EAST PIERCE	Transmission		230.00	115.00	13.20	650	2	0
23	WILD HORSE WIND FARM STATION KITTITAS	Transmission		230.00	34.50	0.00	390	3	0
24	[a] WIND RIDGE KITTITAS	Transmission		230.00	115.00	13.20	325	1	0
25	AIRPORT THURSTON	Distribution		115.00	12.50	0.00	20	1	0
26	ALGER SKAGIT	Distribution		115.00	12.50	0.00	9	1	0
27	ALPAC SOUTH KING	Distribution		115.00	12.50	0.00	50	2	0
28	[b] ANACORTES SKAGIT	Distribution		115.00	12.50	0.00	20	1	0
29	ARCO NORTH FERNDALE	Distribution		115.00	12.50	0.00	80	2	0
30	[c] ARCO SOUTH FERNDALE	Distribution		115.00	12.50	0.00	80	2	0
31	[d] ARCO CENTRAL FERNDALE	Distribution		115.00	12.50	0.00	80	2	0
32	[e] ARDMORE REDMOND	Distribution		115.00	12.50	0.00	50	2	0
33	ASBURY SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
34	AVONDALE REDMOND	Distribution		115.00	12.50	0.00	25	1	0
35	BAKER RIVER LOWER SKAGIT	Distribution		115.00	13.80	0.00	133	2	0
36	BAKER RIVER SW. SKAGIT 1	Distribution		115.00	34.50	0.00	25	1	0
37	BAKER RIVER SW. SKAGIT 2	Distribution		34.50	12.50	0.00	8	1	0
38	BAKER RIVER UPPER SKAGIT 1	Distribution		115.00	13.80	0.00	120	2	0
39	BAKER RIVER UPPER SKAGIT 2	Distribution		12.50	2.40	0.00	3	3	0
40	BAKERVIEW WHATCOM	Distribution		115.00	12.50	0.00	25	1	0
41	BARNES LAKE THURSTON	Distribution		115.00	12.50	0.00	20	1	0
42	BELLINGHAM	Distribution		0.00	0.00	0.00	0	0	0
43	BELLIS WHATCOM	Distribution		115.00	12.50	0.00	25	1	0
44	BELMORE SOUTH WEST KING	Distribution		115.00	12.50	0.00	50	2	0
45	BERTHUSEN WHATCOM	Distribution		115.00	12.50	0.00	25	1	0
46	BIG ROCK SKAGIT	Distribution		115.00	12.50	0.00	20	1	0
47	BIRCH BAY WHATCOM	Distribution		115.00	12.50	0.00	25	1	0
48	BLACKBURN	Distribution		115.00	12.50	0.00	25	1	0
49	BLACK DIAMOND SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
50	BLAINE WHATCOM	Distribution		115.00	12.50	0.00	25	1	0
51	BLUMAER THURSTON	Distribution		115.00	12.50	0.00	25	1	0
52	BONNEY LAKE EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
53	BOW LAKE SOUTH WEST KING	Distribution		115.00	12.50	0.00	75	3	0
54	BREMERTON SOUTH PENNISULA	Distribution		115.00	12.50	0.00	50	2	0
55	BRIDLE TRAILS CENTRAL KING	Distribution		115.00	12.50	0.00	50	2	0
56	[f] BRIGHTWATER IPS NORTH KING	Distribution		115.00	4.00	0.00	13	1	0
57	BRITTON WHATCOM	Distribution		115.00	12.50	0.00	20	1	0
58	BROOKS HILL ISLAND	Distribution		115.00	12.50	0.00	20	1	0
59	BUCKLEY EAST PIERCE	Distribution		55.00	12.50	0.00	19	2	0
60	BUCKLIN HILL NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
61	BURLINGTON SKAGIT	Distribution		115.00	12.50	0.00	25	1	0
62	BURROWS BAY SKAGIT	Distribution		115.00	12.50	0.00	25	1	0
63	CAMBRIDGE SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
64	[g] CAPITOL THURSTON	Distribution		115.00	12.50	0.00	50	2	0
65	CAROLINA WHATCOM	Distribution		115.00	12.50	0.00	20	1	0
66	CASCADE NORTH KING	Distribution		34.50	12.50	0.00	10	0	1
67	CEDARHURST EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
68	CENTER CENTRAL KING 1	Distribution		115.00	13.09	0.00	40	1	0
69	CENTER CENTRAL KING 2	Distribution		115.00	13.09	0.00	25	1	0
70	CENTRAL KITSAP NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
71	CHAMBERS THURSTON	Distribution		115.00	12.50	0.00	25	1	0
72	CHICO SOUTH PENNISULA 1	Distribution		115.00	12.50	0.00	25	1	0
73	CHICO SOUTH PENNISULA 2	Distribution		34.50	12.50	0.00	16	2	0
74	CHRISTENSENS CORNER NORTH PENNISULA	Distribution		115.00	12.50	0.00	20	1	0
75	CHRISTOPHER AUBURN	Distribution		115.00	12.50	0.00	25	1	0
76	CLAY CREEK SOUTH EAST KING	Distribution		55.00	7.00	0.00	1	1	1
77	CLE ELUM KITTITAS	Distribution		115.00	34.50	0.00	50	1	0
78	[h] CLOVER VALLEY ISLAND	Distribution		115.00	12.50	0.00	20	1	0
79	CLYDE HILL CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
80	CLYMER KITTITAS	Distribution		115.00	12.50	0.00	12	1	0
81	COLLEGE CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
82	COTTAGE BROOK NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
83	COUPEVILLE ISLAND	Distribution		115.00	12.50	0.00	20	1	0
84	CRESCENT HARBOR ISLAND	Distribution		115.00	13.00	0.00	25	1	0
85	CRESTWOOD NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
86	CRYSTAL MOUNTAIN GEN. SE KING 1	Distribution		34.50	12.50	0.00	8	1	0
87	CRYSTAL MOUNTAIN GEN. SE KING 2	Distribution		12.50	4.16	0.00	4	1	0
88	CUMBERLAND SE KING	Distribution		115.00	12.50	0.00	25	1	0
89	CUSTER WHATCOM	Distribution		115.00	12.50	0.00	20	1	0
90	DECATUR THURSTON	Distribution		115.00	12.50	0.00	20	1	0
91	DES MOINES SOUTH WEST KING	Distribution		115.00	12.50	0.00	25	1	0
92	DIERINGER EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
93	[i] DUPONT EAST PIERCE	Distribution		115.00	12.50	0.00	20	1	0
94	DUVALL NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
95	EARLINGTON SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
96	EAST PORT ORCHARD SOUTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
97	EAST VALLEY SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
98	EASTGATE CENTRAL KING	Distribution		115.00	12.50	0.00	50	2	0
99	EASTON KITTITAS	Distribution		115.00	12.50	0.00	20	1	0
100	EDGEWOOD EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
101	ELD INLET THURSTON	Distribution		115.00	12.50	0.00	25	1	0
102	ELECTRON GEN. EAST PIERCE	Distribution		115.00	2.40	0.00	25	1	0
103	ELECTRON HEIGHTS EAST PIERCE 1	Distribution		55.00	12.50	0.00	2	1	0
104	ELECTRON HEIGHTS EAST PIERCE 2	Distribution		115.00	55.00	0.00	40	3	0
105	ELECTRON HEIGHTS EAST PIERCE 3	Distribution		55.00	2.40	0.00	3	2	0
106	ELLINGSON SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0
107	ENCOGEN GEN. WHATCOM 1	Distribution		115.00	13.80	0.00	150	3	0
108	ENCOGEN GEN. WHATCOM 2	Distribution		115.00	13.80	0.00	68	1	0
109	ENUMCLAW SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0
110	EVERGREEN NORTH KING	Distribution		115.00	12.50	0.00	50	2	0
111	FABER ISLAND	Distribution		115.00	12.50	0.00	25	1	0
112	FACTORIA CENTER KING	Distribution		115.00	12.50	0.00	50	2	0
113	[(i)] FAIRCHILD EAST PIERCE	Distribution		115.00	12.50	0.00	50	2	0
114	FAIRWOOD CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
115	FALCON SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
116	FALL CITY EAST KING	Distribution		115.00	12.50	0.00	20	1	0
117	FERNWOOD SOUTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
118	FOSS CORNER	Distribution		115.00	0.00	0.00	0	0	0
119	FOUR CORNERS SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0
120	FRAGARIA SOUTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
121	FREDERICKSON GEN STATION E PIERCE 1	Distribution		115.00	13.20	0.00	170	2	0
122	FREDERICKSON GEN STATION E PIERCE 2	Distribution		12.50	4.20	0.00	2	2	0
123	FREDERICKSON GEN STATION E PIERCE 3	Distribution		12.50	0.00	0.00	3	2	0
124	FREDERICKSON GEN STATION E PIERCE 4	Distribution		115.00	6.60	0.00	0	0	0
125	FREDONIA SKAGIT 1	Distribution		115.00	13.20	0.00	110	2	0
126	FREDONIA SKAGIT 2	Distribution		115.00	12.50	13.20	75	0	0
127	FREELAND ISLAND	Distribution		115.00	12.50	0.00	20	1	0
128	FREEWAY SOUTH WEST KING	Distribution		115.00	12.50	0.00	25	1	0
129	FRIENDLY GROVE THURSTON	Distribution		115.00	13.09	0.00	25	1	0
130	FRUITLAND EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
131	GAGES SKAGIT	Distribution		115.00	12.50	0.00	25	1	0
132	GARDELLA EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
133	GLACIER WHATCOM	Distribution		55.00	12.50	0.00	5	1	0
134	GLENCARIN SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
135	GOODES CORNER EAST KING	Distribution		115.00	12.50	0.00	25	1	0
136	GRADY SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
137	GRAVELLY LAKE EAST PIERCE	Distribution		115.00	12.50	0.00	20	1	0
138	GREENBANK ISLAND	Distribution		115.00	12.50	0.00	9	1	0
139	GREENWATER SOUTH EAST KING 1	Distribution		55.00	13.90	0.00	20	1	0
140	GREENWATER SOUTH EAST KING 2	Distribution		34.50	12.50	0.00	8	1	0
141	GRIFFIN THURSTON	Distribution		115.00	12.50	0.00	20	1	0
142	HAMILTON SKAGIT	Distribution		115.00	12.50	0.00	20	1	0
143	HANNEGAN WHATCOM	Distribution		115.00	12.50	0.00	20	1	0
144	HAPPY VALLEY WHATCOM	Distribution		115.00	12.50	0.00	25	1	0
145	HARVEST SOUTH KING	Distribution		115.00	12.50	0.00	50	2	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
146	HAWKS PRAIRIE THURSTON	Distribution		115.00	13.09	0.00	25	1	0
147	HAZELWOOD CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
148	HEMLOCK EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
149	HICKOX SKAGIT	Distribution		115.00	12.50	0.00	25	1	0
150	HIGHLANDS CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
151	HILLCREST ISLAND	Distribution		115.00	12.50	0.00	25	1	0
152	HOBART SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0
153	HOLDEN EAST PIERCE	Distribution		115.00	12.50	0.00	20	1	0
154	HOLLYWOOD NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
155	HOPKINS RIDGE WIND FARM Columbia Cnty	Distribution		115.00	34.50	0.00	167	2	0
156	HOUGHTON NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
157	HYAK EAST KING	Distribution		115.00	12.50	0.00	20	1	0
158	INGLEWOOD NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
159	JOHNSON HILL THURSTON	Distribution		115.00	12.50	0.00	25	1	0
160	JUANITA NORTH KING	Distribution		115.00	12.50	0.00	50	2	0
161	KAPOWSIN EAST PIERCE	Distribution		115.00	12.50	0.00	20	1	0
162	KENDALL WHATCOM	Distribution		115.00	12.50	55.00	30	1	1
163	KENILWORTH NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
164	KENMORE NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
165	KENT SOUTH KING	Distribution		115.00	12.50	0.00	50	2	0
166	KINGSTON	Distribution		115.00	12.50	0.00	25	1	0
167	KITTITAS	Distribution		115.00	12.50	0.00	25	1	0
168	KITTS CORNER SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0
169	KLAHANIE EAST KING	Distribution		230.00	12.50	0.00	25	1	1
170	KNOBLE EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
171	KRAIN CORNER SOUTH EAST KING	Distribution		115.00	55.00	0.00	40	1	3
172	LABOUNTY WHATCOM	Distribution		115.00	12.50	0.00	20	1	0
173	LACEY THURSTON	Distribution		115.00	12.50	0.00	25	1	0
174	LAKE HILLS CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
175	LAKE LEOTA NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
176	LAKE LOUISE WHATCOM	Distribution		115.00	12.50	0.00	20	1	0
177	LAKE MCDONALD EAST KING	Distribution		115.00	12.50	0.00	25	1	0
178	LAKE MERIDIAN SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
179	LAKE TAPPS EAST PIERCE	Distribution		55.00	12.50	0.00	18	1	0
180	LAKE WILDERNESS SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
181	LAKE YOUNGS SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
182	LAKOTA SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0
183	LANGLEY ISLAND	Distribution		115.00	12.50	0.00	20	1	0
184	LAUREL WHATCOM	Distribution		115.00	13.09	0.00	25	1	0
185	LEA HILL SOUTHEAST KING	Distribution		115.00	12.50	0.00	25	1	0
186	(k) LIQUID AIR SOUTH KING	Distribution		115.00	4.20	0.00	20	2	0
187	LOCHLEVEN CENTRAL KING	Distribution		115.00	13.09	0.00	50	2	0
188	LONG LAKE SOUTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
189	LONGMIRE THURSTON	Distribution		115.00	12.50	0.00	25	1	0
190	LUHR BEACH THURSTON	Distribution		115.00	12.50	0.00	25	1	0
191	LYNDEN WHATCOM	Distribution		115.00	12.50	0.00	40	2	0
192	M STREET SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0
193	MANCHESTER SOUTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
194	MANHATTAN SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0
195	MAPLEWOOD CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
196	MARCH POINT COGEN SKAGIT	Distribution		115.00	13.80	0.00	140	3	0

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197	MARINE VIEW SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0
198	MAXWELTON ISLAND COUNTY	Distribution		115.00	13.00	0.00	25	1	0
199	MCALLISTER SPRINGS THURSTON	Distribution		115.00	12.50	0.00	25	1	0
200	MCKENZIE WHATCOM	Distribution		115.00	12.50	0.00	20	1	0
201	MCKINLEY THURSTON	Distribution		115.00	12.50	0.00	25	1	0
202	MCWILLIAMS NORTH PENNISULA	Distribution		115.00	12.50	0.00	20	1	0
203	MEDINA CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
204	MERCER ISLAND CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
205	MERCERWOOD CENTRAL KING	Distribution		115.00	12.50	0.00	20	1	0
206	MERIDETH SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0
207	MIDLAKES CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
208	MIDWAY SOUTH WEST KING	Distribution		115.00	12.50	0.00	0	0	0
209	MILLER BAY NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
210	[(l)] MIRRORMONT EAST KING	Distribution		115.00	12.50	0.00	25	1	0
211	MOBILE UNIT #2 SOUTH KING	Distribution		66.00	12.50	0.00	9	1	0
212	MOBILE UNIT #3 SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
213	MOBILE UNIT #4 SOUTH KING	Distribution		115.00	12.50	0.00	15	1	0
214	MOBILE UNIT #5 SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
215	MOBILE UNIT #6 SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
216	MOTTMAN THURSTON	Distribution		115.00	12.50	0.00	20	1	0
217	MOUNT SI NORTH KING 1	Distribution		115.00	12.50	0.00	25	1	0
218	MOUNT SI NORTH KING 2	Distribution		230.00	115.00	0.00	25	1	0
219	MOUNT VERNON SKAGIT	Distribution		115.00	12.50	0.00	25	1	0
220	MURDEN COVE NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
221	NORKIRK NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
222	NORLUM SKAGIT	Distribution		115.00	12.50	0.00	20	1	0
223	NORPAC SOUTHKING	Distribution		115.00	12.50	0.00	25	1	0
224	NORTH AREA	Distribution		115.00	12.50	0.00	25	0	1
225	NORTH BELLEVUE CENTRAL KING	Distribution		115.00	13.09	0.00	50	2	0
226	[(m)] NORTH BEND EAST KING	Distribution		115.00	12.50	0.00	25	1	0
227	NORTH BOTHELL NORTHKING	Distribution		115.00	12.50	0.00	25	1	0
228	NORTH NORMANDY SOUTHWEST KING	Distribution		115.00	12.50	0.00	20	1	0
229	NORTHRUP CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
230	NORWAY HILL NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
231	NUGENTS CORNER WHATCOM 1	Distribution		34.50	12.50	0.00	8	1	0
232	NUGENTS CORNER WHATCOM 2	Distribution		115.00	34.50	0.00	25	1	0
233	NUGENTS CORNER WHATCOM 3	Distribution		12.50	12.50	0.00	5	1	0
234	OLD TOWN WHATCOM	Distribution		115.00	12.50	0.00	20	1	0
235	[(n)] OLYMPIA BREWERY THURSTON	Distribution		115.00	12.50	0.00	20	1	0
236	[(o)] OLYMPIC ARCO PUMP WHATCOM	Distribution		115.00	4.20	0.00	6	1	0
237	[(p)] OLYMPIC AVON SKAGIT	Distribution		115.00	4.20	0.00	19	2	0
238	[(q)] OLYMPIC MOBIL WHATCOM	Distribution		115.00	4.20	0.00	9	1	0
239	OLYMPIC RENTON SOUTH KING	Distribution		115.00	4.20	0.00	9	1	0
240	[(r)] OLYMPIA SWITCH	Distribution		115.00	0.00	0.00	0	0	0
241	[(s)] OLYMPIC VAIL PIPELINE THURSTON	Distribution		115.00	4.20	0.00	6	1	0
242	OLYMPIC BAYVIEW SKAGIT	Distribution		115.00	4.36	0.00	6	1	0
243	ORCHARD SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
244	ORILLIA SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
245	ORTING EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
246	OSCEOLA SOUTH EAST KING	Distribution		115.00	12.50	0.00	20	1	0

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247	[t] OVERLAKE CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
248	[u] PACCAR CENTRAL KING	Distribution		115.00	12.50	0.00	50	2	0
249	PADILLA BAY PIPELINE SKAGIT 1	Distribution		115.00	12.50	0.00	9	1	0
250	PADILLA BAY PIPELINE SKAGIT 2	Distribution		12.50	4.16	0.00	4	1	0
251	PANTHER LAKE SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
252	PATTERSON THURSTON	Distribution		115.00	12.50	0.00	20	1	0
253	PEASLEY CANYON SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0
254	PETHS CORNER SKAGIT	Distribution		115.00	12.50	0.00	20	1	0
255	PHANTOM LAKE CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
256	PICKERING CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
257	PINE LAKE EAST KING	Distribution		115.00	12.50	0.00	25	1	0
258	PIPE LAKE SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0
259	PLATEAU EAST KING	Distribution		115.00	12.50	0.00	25	1	0
260	PLEASANT GLADE THURSTON	Distribution		115.00	12.50	0.00	25	1	0
261	PLUM STREET THURSTON	Distribution		115.00	13.09	0.00	25	1	0
262	PLYMOUTH WHATCOM	Distribution		115.00	12.50	0.00	25	1	0
263	POINT ROBERTS WHATCOM	Distribution		25.00	12.50	0.00	19	2	0
264	PORT GAMBLE NORTH PENNISULA	Distribution		115.00	12.50	0.00	20	1	0
265	PORT MADISON NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
266	POULSBO NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
267	PRESIDENT PARK CENTRAL KING	Distribution		115.00	13.09	0.00	25	1	0
268	PRINE THURSTON 1	Distribution		115.00	13.09	0.00	25	1	0
269	PRINE THURSTON 2	Distribution		115.00	12.50	0.00	20	1	0
270	QUARRY EAST PIERCE	Distribution		115.00	12.50	0.00	9	1	0
271	RAINIER VIEW THURSTON	Distribution		115.00	12.50	0.00	25	1	0
272	REDMOND NORTH KING	Distribution		115.00	12.50	0.00	50	2	0
273	REDONDO SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0
274	RENTON JUNCTION SOUTH KING	Distribution		115.00	12.50	0.00	50	2	0
275	RHODES LAKE EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
276	RITA STREET SKAGIT	Distribution		115.00	12.50	0.00	20	1	0
277	RIVERBEND SKAGIT	Distribution		115.00	12.50	0.00	20	1	0
278	ROCHESTER THURSTON	Distribution		115.00	12.50	0.00	40	2	0
279	[v] ROCKY POINT SOUTH PENNISULA	Distribution		115.00	12.50	0.00	50	2	0
280	ROEDER WHATCOM	Distribution		115.00	13.09	0.00	20	1	0
281	ROLLING HILLS SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
282	ROSE HILL CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
283	SAHALEE NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
284	[w] SAINT CLAIR THURSTON	Distribution		0.00	0.00	0.00	0	0	0
285	SAMMAMISH NORTH KING	Distribution		230.00	115.00	0.00	25	1	1
286	SCENIC NORTH KING	Distribution		115.00	12.50	0.00	4	1	0
287	SCHUETT WHATCOM	Distribution		115.00	12.50	0.00	20	1	0
288	SEATAC SOUTH KING	Distribution		115.00	13.09	0.00	50	2	0
289	SEHOME WHATCOM	Distribution		115.00	12.50	0.00	25	1	0
290	SEMIAHMOO WHATCOM	Distribution		115.00	12.50	0.00	25	1	0
291	SEQUOIA SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
292	SERWOLD NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
293	SHANNON WHATCOM 1	Distribution		34.50	12.50	0.00	8	1	0
294	SHANNON WHATCOM 2	Distribution		115.00	34.50	0.00	25	1	0
295	SHAW EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
296	SHERIDAN NORTH PENNISULA	Distribution		115.00	12.50	0.00	40	1	0
297	SHERWOOD SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0

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298	SHUFFLETON YARD SOUTH KING 1	Distribution		55.00	12.50	0.00	9	0	0
299	SHUFFLETON YARD SOUTH KING 2	Distribution		55.00	7.20		3	0	0
300	SHUFFLETON YARD SOUTH KING 3	Distribution		12.50	12.50		10	0	0
301	SHUFFLETON YARD SOUTH KING 4	Distribution		12.50	4.20	0.00	8	0	1
302	SHUFFLETON YARD SOUTH KING 5	Distribution		34.50	12.50		10	0	1
303	SHUFFLETON YARD SOUTH KING 6	Distribution		34.50	12.50		10	0	2
304	SHUFFLETON YARD SOUTH KING 7	Distribution		115.00	34.50	0.00	25	0	1
305	SHUFFLETON YARD SOUTH KING 8	Distribution		115.00	12.50	0.00	25	0	3
306	SHUFFLETON YARD SOUTH KING 9	Distribution		115.00	12.50	0.00	13	0	1
307	SHUFFLETON YARD SOUTH KING 10	Distribution		115.00	12.50	0.00	25	1	0
308	SHUFFLETON YARD SOUTH KING 11	Distribution		230.00	36.20		50	0	1
309	SHUFFLETON YARD SOUTH KING 12	Distribution		115.00	12.50	0.00	25	0	4
310	SHUFFLETON YARD SOUTH KING 13	Distribution		12.50	12.50		5	0	1
311	SPANAWAY EAST PIERCE	Distribution		115.00	7.20				1
312	SILVERDALE NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
313	SINCLAIR INLET SOUTH PENNISULA	Distribution		115.00	12.50	0.00	20	1	0
314	SKYKOMISH NORTH KING	Distribution		115.00	12.50	0.00	9	1	0
315	SLATER WHATCOM	Distribution		115.00	12.50	0.00	20	1	0
316	SNOQUALMIE EAST KING	Distribution		115.00	12.50	0.00	25	1	0
317	SNOQUALMIE (BLACK CREEK GEN)	Distribution		34.50	12.50	0.00	5	1	0
318	SNOQUALMIE GEN. #1	Distribution		117.90	6.90	2.00	20	1	0
319	SNOQUALMIE GEN. #2	Distribution		117.90	7.20	0.00	53	1	0
320	SOMERSET CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
321	SOOS CREEK SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
322	SOUTH BELLEVUE CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0
323	SOUTH KEYPORT NORTH PENNISULA	Distribution		115.00	12.50	0.00	20	1	0
324	SOUTH KIRKLAND NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
325	SOUTH MERCER CENTRAL KING	Distribution		115.00	12.50	0.00	20	1	0
326	SOUTHWICK THURSTON	Distribution		115.00	12.50	0.00	25	1	0
327	SOUTHCENTER SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
328	SOUTH WHIDBEY SWITCH ISLAND	Distribution		115.00	0.00	0.00	0	0	0
329	SPANAWAY EAST PIERCE 1	Distribution		115.00	12.50	0.00	20	1	0
330	SPIRITBROOK NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
331	SPURGEON CREEK	Distribution		115.00	12.50	0.00	25	1	0
332	[x] STARWOOD SOUTH KING	Distribution		115.00	12.50	0.00	50	2	0
333	STATE STREET WHATCOM	Distribution		115.00	13.09	0.00	25	1	0
334	STERLING NORTH KING	Distribution		115.00	12.50	0.00	50	2	0
335	STEWART EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
336	SUMAS GEN STATION	Distribution		115.00	13.80	0.00	240	2	0
337	SUMMIT PARK SKAGIT	Distribution		115.00	12.50	0.00	20	1	0
338	SUMNER EAST PIERCE	Distribution		115.00	12.50	0.00	20	1	0
339	SUNRISE EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
340	SWANTOWN ISLAND	Distribution		115.00	12.50	0.00	20	1	0
341	[y] SWEPTWING SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0
342	[z] TANGLEWILDE THURSTON	Distribution		115.00	12.50	0.00	20	1	0
343	[aa] TEN MILE WHATCOM	Distribution		115.00	4.20	0.00	9	1	0
344	TEXACO EAST SKAGIT	Distribution		115.00	13.80	0.00	50	2	0
345	TEXACO WEST SKAGIT	Distribution		115.00	13.80	0.00	80	2	0
346	THORP KITTITAS	Distribution		34.50	12.50	0.00	9	1	0
347	THURSTON THURSTON	Distribution		115.00	12.50	0.00	50	2	0
348	TILLICUM EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
349	TOLT NORTH KNG	Distribution		115.00	12.50	0.00	25	1	0
350	TOTEM NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
351	TRACYTON NORTH PENNISULA	Distribution		115.00	12.50	0.00	20	1	0
352	UNION HILL EAST KING	Distribution		115.00	13.09	0.00	25	1	0
353	VALLEY JUNCTION	Distribution		115.00	0.00	0.00	0	0	0
354	VAN WYCK WHATCOM	Distribution		115.00	12.50	0.00	9	1	0
355	[ab] VASHON SOUTH PENNISULA	Distribution		115.00	12.50	0.00	50	2	0
356	VICTORIA PARK SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0
357	[ac] VIKING WHATCOM	Distribution		115.00	12.50	0.00	20	1	0
358	VISTA WHATCOM	Distribution		115.00	12.50	0.00	20	1	0
359	VITULLI NORTH KING	Distribution		115.00	12.50	0.00	50	2	0
360	WABASH SOUTH EAST KING	Distribution		55.00	12.50	0.00	9	1	0
361	WAYNE NORTH KING	Distribution		115.00	12.50	0.00	25	1	0
362	WEST AUBURN SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0
363	WEST CAMPUS SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0
364	WEST ISSAQUAH EAST KING	Distribution		115.00	13.09	0.00	25	1	0
365	[ad] WEST OLYMPIA THURSTON	Distribution		115.00	12.50	0.00	25	1	0
366	WHIDBEY ISLAND OAK HARBOR	Distribution		0.00	0.00	0.00	0	0	0
367	WEYERHAEUSER SW KING	Distribution		115.00	12.50	0.00	20	1	0
368	WEYERHAEUSER WHR BRANCH	Distribution		55.00	4.16	0.00	8	3	0
369	WHITEHORN WHATCOM	Distribution		115.00	13.20	0.00	170	2	0
370	WHITE RIVER TRANSM. EAST PIERCE 1	Distribution		115.00	55.00	0.00	83	3	0
371	WHITE RIVER TRANSM. EAST PIERCE 2	Distribution		55.00	7.20	0.00	3	3	0
372	WHITEHORN GEN WHATCOM 1	Distribution		12.50	0.00	0.00	1	2	0
373	WHITEHORN GEN WHATCOM 2	Distribution		12.50	0.50	0.00	2	2	0
374	WHITEHORN GEN WHATCOM 3	Distribution		12.50	4.20	0.00	2	2	0
375	WILKESON EAST PIERCE	Distribution		55.00	12.50	0.00	9	1	0
376	WILSON SKAGIT	Distribution		115.00	12.50	0.00	25	1	0
377	WINSLOW NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0
378	WOBURN WHATCOM	Distribution		115.00	12.50	0.00	25	1	0
379	WOLDALE KITTITAS	Distribution		115.00	12.50	0.00	20	1	0
380	WOODLAND EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0
381	YELM THURSTON	Distribution		115.00	12.50	0.00	25	1	0
382	ZENITH SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0
383	TotalDistributionSubstationMember			38,256.30	4,669	70	9,885	399	25
384	TotalTransmissionSubstationMember			5,815.00	2,041	246	8,548	34	1
385	Total			44,071.30	6,710	317	18,433	433	26

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1	Static Capacitor	2	42
2	Static Capacitor	1	42
3		0	0
4		0	0
5		0	0
6	Reactor	1	10
7		0	0
8		0	0
9	Static Capacitor	1	23
10	Static Capacitor	1	42
11	Static Capacitor	1	42
12		0	0
13		0	0
14	Reactor	1	10
15		0	0
16	Static Capacitor	2	84
17	Static Capacitor	2	84
18		0	0
19	Static Capacitor	1	84
20	Static Capacitor	1	42
21		0	0
22	Static Capacitor	1	45
23	Static Capacitor	7	66
24	Reactor	1	45
25	Static Capacitor	1	2
26		0	0
27	Static Capacitor	2	6
28	Static Capacitor	1	5
29	Static Capacitor	1	24
30	Static Capacitor	1	24
31		0	0
32	Static Capacitor	2	10
33	Static Capacitor	1	5
34	Static Capacitor	0	0
35		0	0
36		0	0
37		0	0
38		0	0
39		0	0
40	Static Capacitor	1	5
41	Static Capacitor	1	5
42	Static Capacitor	1	21
43	Static Capacitor	1	5
44	Static Capacitor	2	9
45	Static Capacitor	1	5
46	Static Capacitor	1	5
47	Static Capacitor	1	5
48	Static Capacitor	1	5
49	Static Capacitor	1	2
50	Static Capacitor	1	5
51	Static Capacitor	1	2
52	Static Capacitor	1	2
53	Static Capacitor	1	5

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
54	Static Capacitor	2	12
55	Static Capacitor	2	11
56		0	0
57	Static Capacitor	1	5
58		0	0
59	Static Capacitor	1	2
60		0	0
61	Static Capacitor	1	5
62		0	0
63	Static Capacitor	1	5
64		0	0
65	Static Capacitor	1	5
66		0	0
67	Static Capacitor	1	2
68	Static Capacitor	1	6
69	Static Capacitor	1	6
70	Static Capacitor	1	2
71	Static Capacitor	1	5
72	Static Capacitor	1	2
73		0	0
74	Static Capacitor	1	5
75	Static Capacitor	1	5
76		0	0
77		0	0
78	Static Capacitor	1	5
79	Static Capacitor	1	5
80		0	0
81	Static Capacitor	1	5
82	Static Capacitor	1	5
83		0	0
84	Static Capacitor	1	5
85	Static Capacitor	1	2
86	Static Capacitor	0	0
87		0	0
88	Static Capacitor	1	2
89	Static Capacitor	1	5
90	Static Capacitor	1	5
91	Static Capacitor	1	5
92		0	0
93	Static Capacitor	1	5
94		0	0
95	Static Capacitor	2	10
96	Static Capacitor	1	5
97	Static Capacitor	1	5
98	Static Capacitor	1	5
99		0	0
100	Static Capacitor	1	5
101	Static Capacitor	1	2
102		0	0
103		0	0
104		0	0
105		0	0
106	Static Capacitor	1	4

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
107		0	0
108		0	0
109	Static Capacitor	1	5
110	Static Capacitor	2	10
111	Static Capacitor	1	5
112	Static Capacitor	2	10
113	Static Capacitor	1	5
114	Static Capacitor	1	3
115	Static Capacitor	1	5
116		0	0
117	Static Capacitor	1	2
118	Static Capacitor	1	23
119	Static Capacitor	1	5
120	Static Capacitor	1	5
121		0	0
122		0	0
123		0	0
124	Spare GSU	0	0
125		0	0
126	Spare GSU	0	0
127	Static Capacitor	1	2
128	Static Capacitor	1	5
129	Static Capacitor	1	5
130	Static Capacitor	1	2
131	Static Capacitor	1	5
132	Static Capacitor	1	5
133		0	0
134	Static Capacitor	1	5
135	Static Capacitor	1	2
136	Static Capacitor	1	2
137	Static Capacitor	1	5
138		0	0
139	Static Capacitor	1	5
140		0	0
141	Static Capacitor	1	2
142		0	0
143	Static Capacitor	1	5
144		0	0
145	Static Capacitor	1	5
146	Static Capacitor	1	5
147	Static Capacitor	1	5
148	Static Capacitor	1	5
149		0	0
150	Static Capacitor	1	6
151	Static Capacitor	1	5
152	Static Capacitor	1	2
153	Static Capacitor	1	2
154	Static Capacitor	1	5
155	Static Capacitor	2	22
156	Static Capacitor	1	5
157	Static Capacitor	1	5
158	Static Capacitor	1	5
159	Static Capacitor	1	5

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
160	Static Capacitor	2	10
161	Static Capacitor	1	5
162	Static Capacitor	1	2
163	Static Capacitor	1	5
164	Static Capacitor	1	5
165	Static Capacitor	2	8
166	Static Capacitor	1	5
167	Static Capacitor	1	5
168	Static Capacitor	1	5
169	Static Capacitor	1	5
170	Static Capacitor	1	5
171		0	0
172	Static Capacitor	1	5
173	Static Capacitor	1	4
174	Static Capacitor	1	5
175	Static Capacitor	1	5
176	Static Capacitor	1	5
177	Static Capacitor	1	2
178		0	0
179	Static Capacitor	1	2
180	Static Capacitor	1	5
181	Static Capacitor	1	5
182	Static Capacitor	1	5
183		0	0
184	Static Capacitor	1	5
185	Static Capacitor	1	3
186		0	0
187	Static Capacitor	2	12
188	Static Capacitor	1	5
189	Static Capacitor	1	5
190	Static Capacitor	1	2
191	Static Capacitor	2	10
192	Static Capacitor	1	5
193	Static Capacitor	1	2
194	Static Capacitor	1	5
195	Static Capacitor	1	5
196		0	0
197	Static Capacitor	1	5
198	Static Capacitor	1	5
199		0	0
200	Static Capacitor	1	5
201	Static Capacitor	1	5
202	Static Capacitor	1	5
203		0	0
204		0	0
205		0	0
206	Static Capacitor	1	5
207	Static Capacitor	1	5
208	Static Capacitor	1	39
209	Static Capacitor	1	5
210	Static Capacitor	1	5
211		0	0
212		0	0

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
213		0	0
214		0	0
215		0	0
216	Static Capacitor	1	5
217	Static Capacitor	1	5
218	Static Capacitor	1	2
219	Static Capacitor	1	2
220	Static Capacitor	1	5
221	Static Capacitor	1	5
222		0	0
223	Static Capacitor	1	5
224		0	0
225	Static Capacitor	2	10
226	Static Capacitor	1	5
227	Static Capacitor	1	5
228	Static Capacitor	1	5
229	Static Capacitor	1	5
230	Static Capacitor	1	5
231		0	0
232		0	0
233		0	0
234	Static Capacitor	1	5
235	Static Capacitor	1	42
236		0	0
237		0	0
238		0	0
239		0	0
240	Static Capacitor	1	42
241		0	0
242		0	0
243	Static Capacitor	1	4
244	Static Capacitor	1	5
245	Static Capacitor	1	2
246	Static Capacitor	1	5
247		0	0
248	Static Capacitor	2	10
249		0	0
250		0	0
251	Static Capacitor	1	5
252	Static Capacitor	1	2
253	Static Capacitor	1	5
254	Static Capacitor	1	5
255	Static Capacitor	1	5
256	Static Capacitor	1	5
257	Static Capacitor	1	5
258	Static Capacitor	1	3
259	Static Capacitor	1	5
260	Static Capacitor	1	5
261	Static Capacitor	1	5
262		0	0
263		0	0
264	Static Capacitor	1	4
265	Static Capacitor	1	5

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
266		0	0
267	Static Capacitor	1	5
268	Static Capacitor	1	5
269	Static Capacitor	1	5
270		0	0
271	Static Capacitor	1	5
272	Static Capacitor	2	10
273	Static Capacitor	1	5
274	Static Capacitor	2	10
275	Static Capacitor	1	5
276		0	0
277	Static Capacitor	1	5
278	Static Capacitor	1	5
279		0	0
280	Static Capacitor	1	5
281	Static Capacitor	0	0
282	Static Capacitor	1	5
283	Static Capacitor	1	5
284	Static Capacitor	1	42
285	Static Capacitor	1	5
286		0	0
287		0	0
288		0	0
289	Static Capacitor	1	5
290	Static Capacitor	1	5
291	Static Capacitor	1	5
292	Static Capacitor	1	5
293		0	0
294		0	0
295	Static Capacitor	1	2
296	Static Capacitor	1	5
297	Static Capacitor	1	5
298		0	0
299		0	0
300		0	0
301		0	0
302		0	0
303		0	0
304		0	0
305		0	0
306		0	0
307		0	0
308		0	0
309		0	0
310			
311		0	0
312	Static Capacitor	1	5
313	Static Capacitor	1	2
314		0	0
315	Static Capacitor	1	5
316		0	0
317		0	0
318		0	0

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
319		0	0
320	Static Capacitor	1	5
321	Static Capacitor	1	4
322	Static Capacitor	1	5
323	Static Capacitor	1	4
324	Static Capacitor	1	5
325		0	0
326	Static Capacitor	1	5
327	Static Capacitor	1	5
328	Static Capacitor	2	42
329	Static Capacitor	1	5
330	Static Capacitor	1	2
331	Static Capacitor	1	5
332	Static Capacitor	2	10
333	Static Capacitor	1	5
334	Static Capacitor	2	10
335	Static Capacitor	1	2
336		0	0
337	Static Capacitor	1	5
338	Static Capacitor	1	2
339	Static Capacitor	1	5
340		0	0
341	Static Capacitor	1	3
342	Static Capacitor	1	5
343		0	0
344		0	0
345		0	0
346		0	0
347	Static Capacitor	1	5
348	Static Capacitor	1	5
349		0	0
350	Static Capacitor	1	5
351	Static Capacitor	1	2
352	Static Capacitor	1	5
353	Static Capacitor	1	23
354		0	0
355	Static Capacitor	1	5
356	Static Capacitor	1	5
357	Static Capacitor	1	5
358	Static Capacitor	1	5
359	Static Capacitor	2	10
360		0	0
361		0	0
362	Static Capacitor	1	4
363	Static Capacitor	1	2
364	Static Capacitor	1	5
365	Static Capacitor	1	2
366	Static Capacitor	1	23
367		0	0
368		0	0
369		0	0
370		0	0
371		0	0

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
372		0	0
373		0	0
374		0	0
375		0	0
376	Static Capacitor	1	5
377		0	0
378		0	0
379		0	0
380	Static Capacitor	1	5
381	Static Capacitor	2	26
382	Static Capacitor	1	2
383		255	1,463
384		23	661
385		278	2,124

FOOTNOTE DATA

(a) Concept: SubstationNameAndLocation

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.

(b) Concept: SubstationNameAndLocation

Safeway Distribution Center leases PSE owned transformer at Alpac (Algona-Pacific / Boeing-Auburn #2) Substation. Service started November 2004.

(c) Concept: SubstationNameAndLocation

BP West Coast Products leases PSE owned transformer at ARCO North Substation under schedule 449.

(d) Concept: SubstationNameAndLocation

BP West Cost Products leases PSE owned transformer at ARCO South Substation under schedule 449.

(e) Concept: SubstationNameAndLocation

BP West Coast Products leases PSE owned transformer at ARCO Central Substation under schedule 449.

(f) Concept: SubstationNameAndLocation

Waste Water Treatment Division - Brightwater leases PSE owned transformer at Brightwater Substation. Expiration 5/21/2030.

(g) Concept: SubstationNameAndLocation

State of Washington Admin leases PSE owned transformer at Capitol Substation. Service started November 1972. This lease was renewed on 8.2022 in amount of $10,768 for another 10 years. Consolidated Technology Services lease was renewed on 8.2022 in amount of $13,245 for another 10 years.

(h) Concept: SubstationNameAndLocation

Navy Ault leases PSE owned transformer at Clover Valley Substation. Service started November 1972.

(i) Concept: SubstationNameAndLocation

Center Drive Owners Association leases transformer and feeder at Dupont Substation. Service began 12/1/2018.

(j) Concept: SubstationNameAndLocation

Sch 62 Lease was signed between PSE and BCC Puyallup, LLC for 10 year period Starting July 26, 2020.

(k) Concept: SubstationNameAndLocation

Sch 62 Lease was signed between PSE and Airgas USA Inc. for 10 year period starting August 1, 2023.

(l) Concept: SubstationNameAndLocation

BioEnergy leases PSE owned transformer at Mirrormont Substation. This lease was renewed on 3.2022 in amount of $14,135 for another 10 years.

(m) Concept: SubstationNameAndLocation

AT&T leases PSE owned transformer at North Bothell Substation.

(n) Concept: SubstationNameAndLocation

Praxair and Olympic Pipeline lease PSE owned transformers at Olympic Arco Pump Substation. Services started July 1979.

(o) Concept: SubstationNameAndLocation

BP Pipelines (North America) leases PSE owned transformer at Olympic Avon Substation. Service started April 2004.

(p) Concept: SubstationNameAndLocation

BP Pipelines (North America) leases PSE owned transformer at Olympic Mobil Substation. Service started April 2004.

(q) Concept: SubstationNameAndLocation

BP Pipelines (North America) leases PSE owned transformer at Olympic Renton Substation. Service started April 2004.

(r) Concept: SubstationNameAndLocation

BP Pipelines (North America) leases PSE owned transformer at Olympic Vail Substation. Service started April 2004.

(s) Concept: SubstationNameAndLocation

Olympic Pipeline leases PSE owned transformer at Olympic Bayview Substation.

(t) Concept: SubstationNameAndLocation

PACCAR Inc. leases PSE owned transformer at PACCAR Substation. Service started December 1992.

(u) Concept: SubstationNameAndLocation

Olympic Pipeline leases PSE owned transformer at Padilla Bay Substation.

(v) Concept: SubstationNameAndLocation

Bellingham Cold Storage leases PSE owned transformer at Roeder Substation. Service started May 1967.

(w) Concept: SubstationNameAndLocation

AT&T Wireless Services Leases PSE Owned transformer service from Sammamish Sub

(x) Concept: SubstationNameAndLocation

Microsoft leases PSE owned transformer at Sterling Substation. Service started 2010.

(y) Concept: SubstationNameAndLocation

Trans Mountain Pipeline leases PSE owned transformer at Ten Mile Substation. The substation was energized 10/17/08.

(z) Concept: SubstationNameAndLocation

Shell leases PSE owned transformer at Texaco East Substation under Schedule 449.

(aa) Concept: SubstationNameAndLocation

Shell leases PSE owned transformer at Texaco West Substation under Schedule 449.

(ab) Concept: SubstationNameAndLocation

Western Washington University leases PSE owned transformer at Viking Substation. This lease will be renewed in 2.2023 in the amount of $1,414 for another 10 years.

(ac) Concept: SubstationNameAndLocation

AT&T Wireless and The Seattle Times lease PSE owned transformers at Vitulli Substation. Services started December 2006 and August 1991.

(ad) Concept: SubstationNameAndLocation

Federal Way Campus leases PSE owned transformer at Weyerhaeuser Substation.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/16/2024	Year/Period of Report End of: 2023/ 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 Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
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19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Operations and Maintenance Expenses	Puget Energy, Inc.	146	309,289
22	Operations and Maintenance Expenses	Puget LNG, LLC	146	600,219
23	General and Adminstrative Expenses	Puget Holdings, LLC	146	1,656,678
24	Operations and Maintenance Expenses	Puget Holdings, LLC	146	599,520
42				