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: 2022/ Q4

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

GENERAL INFORMATION

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.

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:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

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.

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

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

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:

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

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

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.

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.

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.

When to Submit

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

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

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

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

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.

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.

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).

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.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

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

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.

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

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.

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:

'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;

'Person' means an individual or a corporation;

'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;

'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; ......

"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

'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.

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 any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

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.

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.

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: 2022/ 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) 04/14/2023

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) 04/14/2023

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: 04/14/2023	Year/Period of Report End of: 2022/ 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".

44	**Sales of Electricity by Rate Schedules**	304	
45	**Sales for Resale**	310	
46	**Electric Operation and Maintenance Expenses**	320	
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	
0	**Energy Storage Operations (Large Plants)**	414	
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	N/A
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		

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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: 04/14/2023	Year/Period of Report End of: 2022/ 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: 04/14/2023	Year/Period of Report End of: 2022/ 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: 04/14/2023	Year/Period of Report End of: 2022/ 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	991,585		
2	Executive Vice President and Chief Financial Officer	Kazi Hasan	542,348		
3	Executive Vice President and Chief Operating Officer	Allen (Wade) Smith	262,500	2022-07-18	
4	Senior Vice President, General Counsel and Chief Sustainability Officer	Lorna Luebbe	296,739	2022-12-01	
5	Senior Vice President Shared Services & Chief Information Officer	Margaret F. Hopkins	423,946		
6	Senior Vice President and Chief Customer Officer	Andrew Wappler	399,645		
7	Vice President, External Affairs	Ken Johnson	286,683		
8	Vice President, Energy Supply	Ron Roberts	356,452		
9	Vice President and Chief Human Resources Officer	Kim Collier	338,453		
10	Vice President, Clean Energy Strategy and Planning	Josh Jacobs	307,681		
11	Vice President, Energy Delivery	Daniel Koch	276,447		
12	Former Senior Vice President, General Counsel and Chief Ethics and Compliance Officer	Steve R. Secrist	491,021		2022-12-01
13	Director, Controller and Principal Accounting Officer	Stacy Smith	169,240	2022-12-19	
14	Director, Corporate Treasurer	Cara Peterman	244,691		
15	Former Director, Controller and Principal Accounting Officer	Stephen J. King	246,682		2022-11-17
16	Former Senior Vice President of Regulatory and Strategy	Adrian J. Rodriguez	235,324		2022-05-03

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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	Grant Hodgkins	Victoria, B.C.		
7	Thomas King	Houston, Texas		
8	Mary Kipp (President & CEO)	Bellevue, WA		
9	Jean-Paul Marmoreo	Toronto, Ontario		
10	Paul McMillan	Calgary, Alberta		
11	[(b)] Diana Birkett Rakow	Seattle, WA		
12	Aaron Rubin	New York, NY		
13	Martijn Verwoest	Netherlands		
14	Steven Zucchet	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 5, 2022, Diana Birkett Rakow was elected to serve on the Board of Directors of Puget Sound Energy.

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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	ER23-22-000 Amendment to OATT Attachment H-1 revision of formula rate Protocols revision partially accepted by FERC
5	FERC Electric Tariff Amendment	ER23-1249-000 Updated amendment to OATT Attachment H-1 revision of formula rate Protocols Filing not yet acepted by FERC

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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

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	20221006-5000	10/05/2022	ER23-22-000	Commission Section 206 proceeding revising PSE OATT Attachment H-1	OATT rates Schedule 1,7,8,10
5	20230306-5052	03/06/2023	ER23-1249-000	Commission Section 206 proceeding revising PSE OATT Attachment H-1	OATT rates Schedule 1,7,8,10

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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: 04/14/2023	Year/Period of Report End of: 2022/ 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: 04/14/2023	Year/Period of Report End of: 2022/ 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
Ellensburg	Kittitas	Electric	Expired		$ -
Federal Way	King	Electric	Expired		$ -
Kirkland	King	Natural Gas	Expired		$ -

Q2: None

Q3:

Location (WA)	County	Type	Category	Initial Term	Consideration
Lake Forest Park	King	Electric and Natural Gas	New	15 years	$ -
Concrete	Skagit	Electric	New	25 years	$ -
Burlington	Skagit	Electric	New	25 years	$ -
Bainbridge Island	Kitsap	Electric	Expired		$ -
Hamilton	Skagit	Electric	Expired		$ -

Q4: None

2. None.

3. None.

4. None.

5. None.

6.

Credit Facilities

As of December 31, 2022, no amount was drawn under PSE's credit facility and $357.0 million was outstanding under the commercial paper program. Outside of the credit agreement, PSE had a $2.3 million letter of credit in support of a long-term transmission contract and had $28.0 million issued under a standby letter of credit in support of natural gas purchases.

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, $1.4 billion was available to be issued. The shelf registration will expire in August 2025. 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, 2021.

7. None.

8.

Non-represented employees received on average a 3.50% increase effective on March 1, 2022. Employees of the IBEW received a 3.0% salary increase effective on January 1, 2022. Employees of the UA received a 3.5% salary increase effective on October 1, 2022. The estimated annual effect of these changes is $11.3 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

PSE filed a general rate case (GRC) which includes a three-year multiyear rate plan with the Washington Commission on January 31, 2022, requesting an overall increase in electric and natural gas rates of 13.6% and 13.0% respectively in 2023; 2.5% and 2.3%, respectively in 2024; and 1.2% and 1.8%, respectively, in 2025. PSE requested a return on equity of 9.9% in all three rate years. PSE requested an overall rate of return of 7.39% in 2023; 7.44% in 2024; and 7.49% in 2025. The filing requests recovery of forecasted plant additions through 2022 as required by Revised Code of Washington (RCW) 80.28.425 as well as forecasted plant additions through 2025, the final year of the multiyear rate plan.

On January 6, 2023, the Washington Commission approved PSE's natural gas rates in its compliance filing with an overall increase of $70.8 million or 6.4% in 2023 and $19.5 million or 1.65% 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 increase of $247.0 million or 10.75% in 2023 and $33.1 million or 1.33% in 2024 with an effective date of January 11, 2023.

Revenue Decoupling Adjustment Mechanism

On January 6, 2023, the Washington Commission approved the natural gas 2022 GRC filing. As part of this filing the annual 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.

Power Cost Adjustment Clause Filing

PSE exceeded the $20.0 million cumulative deferral balance in its PCA mechanism in 2021. During 2021, actual power costs were higher than baseline power costs, thereby creating an under-recovery of $68.0 million. Under the terms of the PCA's sharing mechanism for under-recovered power costs, 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. On October 27, 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.

Purchased Gas Adjustment Mechanism

On October 27, 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.

On November 15, 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.

Environmental Remediation

The Company is subject to environmental laws and regulations by the federal, state and local authorities and is required to undertake certain environmental investigative and remedial efforts as a result of these laws and regulations. The Company has been named by the Environmental Protection Agency (EPA), the Washington State Department of Ecology and/or other

third parties as potentially responsible at several contaminated sites and 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. Management believes it is probable and reasonably estimable that the impact of the potential outcomes of disputes with certain property owners and other potentially responsible parties will result in environmental remediation costs of $84.4 million for natural gas and $48.3 million for electric. The Company believes a significant portion of its past and future environmental remediation costs are recoverable from insurance companies, from third parties or from customers under a Washington Commission order. The Company is also subject to cost-sharing agreements with third parties regarding environmental remediation projects in Seattle, Tacoma, Everett, and Bellingham, Washington.

As of December 31, 2022, the Company's share of future remediation costs is estimated to be approximately $61.5 million. The Company's deferred electric environmental costs are $51.5 million and $52.2 million at December 31, 2022 and 2021, respectively, net of insurance proceeds. The Company's deferred natural gas environmental costs are $90.4 million and $75.8 million at December 31, 2022 and 2021, respectively, net of insurance proceeds.

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. 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 accounting criteria were not met as of December 31, 2022. As such, Colstrip Units 3 and 4 are classified as Electric Utility Plant on the Company's balance sheet as of December 31, 2022.

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.

On May 19, 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 October 13, 2021, the United States District Court for the District of Montana issued a preliminary injunction finding it likely that Senate Bill 266 unconstitutionally violates the Commerce Clause and Contract Clause of the United States Constitution. Since then, a motion for summary judgment was filed requesting a permanent injunction against enforcement of Senate Bill 266. On September 29, 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. On October 18, 2022, the U.S. District Court Judge accepted in full the magistrate judge recommendation for a permanent injunction against enforcement of Senate Bill 266.

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 will provide peak-shaving services to PSE's natural gas customers, and will provide 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, $245.7 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, 2022, 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 22, 2022, Christopher Hind and Mary McWilliams were removed from the board of directors, and Aaron Rubin and Chris Parker were appointed as board directors of PSE.

Mr. Rubin is currently responsible for Macquarie Asset Management's Real Assets investment team that focuses on sustainable energy investments in the Americas. Since joining Macquarie in 2008, Mr. Rubin has had responsibility for investment origination and execution and the management of portfolio companies. Mr. Rubin currently serves on the board of directors of Cyrq Energy, Cleco Corporation and Lordstown Energy Center. Mr. Rubin was selected by Clean Energy JV Sub 1, LP 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. Mr. Rubin will not receive any director compensation from the Companies for his service as an Owner Director on the Boards, but will be reimbursed for out-of-pocket expenses.

Mr. Parker is currently a member of the Ontario Teachers' Pension Plan North America Infrastructure team where he focuses on origination, execution and management of infrastructure investments. He joined Ontario Teachers' Pension Plan in 2011 and has served on the board of directors of Northern Star Generation, Intergen, Express Pipeline, Ontario Teachers' New Zealand Forest Investments and Sydney Desalination Plant. He currently serves on the board of directors of Chicago Skyway. Prior to joining Ontario Teachers', Chris worked on power and utility investments at Brookfield Asset Management. Mr. Parker was selected by Clean Energy JV Sub 2, LP 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. Mr. Parker will not receive any director compensation from the Companies for his service as an Owner Director on the Boards, but will be reimbursed for out-of-pocket expenses.

b. Effective March 1, 2022, Lorna Luebbe, director and Assistant General Counsel, has been named Vice President of Sustainability and Deputy General Counsel.

c. On May 2, 2022, Adrian Rodriguez, Senior Vice President of Regulatory and Strategy informed PSE that he will be departing on or about May 20, 2022 to pursue another opportunity.

d. Effective May 5, 2022, the board of directors (the "Board") of Puget Sound Energy, Inc. ("PSE") appointed and elected Diana Birkett Rakow to the Board of PSE.

Ms. Birkett Rakow currently serves as Senior Vice President for Public Affairs & Sustainability at Alaska Air Group, Inc., which position she has held since November 2021. She previously served as Vice President of External Relations at Alaska Airlines from September 2017 to February 2021. Ms. Birkett Rakow also currently serves as the current board chair for the Alaska Airlines Foundation, and serves on the boards of Philanthropy Northwest, the Bay Area Council, and the Pacific Science Center.

e. On July 1, 2022, Puget Sound Energy, Inc. and Puget Energy, Inc. (together, the "Companies") announced that Wade Smith has been appointed to serve as Executive Vice President and Chief Operating Officer ("COO") of the Companies. Mr. Smith will report to Mary E. Kipp, the Company's President and Chief Executive Officer. It is anticipated that Mr. Smith will begin his service on July 18, 2022.

Mr. Smith, who is 57, previously served as the Senior Vice President, Electric Operations of Pacific Gas and Electric Company, a role he held since May 2021. Prior to this, Mr. Smith served American Electric Power Company, Inc., as Senior Vice President, Grid Development from 2015 to 2021, and as President and Chief Operating Officer of AEP Texas from 2010 to 2015.

f. On October 11, 2022, Steve Secrist, Senior Vice President, General Counsel and Chief Ethics & Compliance Officer of the Companies informed PSE that he will retire from his positions effective on November 30, 2022.

g. On October 10, 2022, the company announced that Lorna Luebbe, Vice President of Sustainability and Deputy General Counsel, will assume the role of Senior Vice President, Chief Sustainability Office and General Counsel effective on December 1, 2022.

h. On October 10, 2022, the company announced that Sam Osborne, Director, Assistant General Counsel, will assume the role of Corporate Secretary effective on December 1, 2022.

i. On November 7, 2022, Stephen J. King notified Puget Sound Energy, Inc. and Puget Energy, Inc. (together, the "Companies") of his intent to resign from his position as Controller and Principal Accounting Officer of the Companies, effective November 17, 2022. Following Mr. King's departure, Matthew R. Marcelia, the Companies' Director of Tax, will serve as interim Controller and Principal Accounting Officer of the Companies.

j. On December 19, 2022, Puget Sound Energy, Inc. and Puget Energy, Inc. (together, the "Companies") appointed Stacy Smith to serve as Controller and Principal Accounting Officer of the Companies. Mr. Smith will report to Kazi Hasan, the Company's Executive Vice President and Chief Financial Officer.

Mr. Smith, who is 37, previously served as the Manager of Revenue Requirements of the Companies since 2019. Prior to this, Mr. Smith served as the Manager of Energy and Derivatives Accounting of the Companies from 2018 to 2019, and as the Manager of Contract to Pay Accounting of Nike, Inc. from 2017 to 2018.

k. 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. The Boards have not yet determined the board committee or committees, if any, on which Ms. Gregoire will serve.

Ms. Gregoire, age 75, currently serves as the CEO of Challenge Seattle, an alliance of CEOs from 21 of the region's largest private-sector employers, a position she has held since 2015. Prior this role Ms. Gregoire served for two terms as the Governor of the State of Washington from 2005 until 2013. Before serving as Governor Ms. Gregoire served for three terms as the Attorney General for the State of Washington from 1993 to 2005. In addition to her role as CEO of Challenge Seattle, Ms. Gregoire has served as the former chair of the Fred Hutch Cancer Research Center, a member of the National Bipartisan Governor's Council, and as chair of the National Export-Import Bank Advisory Board.

14. None.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	17,795,827,941	17,074,294,317
3	Construction Work in Progress (107)	200	861,801,465	870,203,996
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		18,657,629,406	17,944,498,313
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	7,461,206,807	7,068,316,701
6	Net Utility Plant (Enter Total of line 4 less 5)		11,196,422,599	10,876,181,612
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)		11,196,422,599	10,876,181,612
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)		8,783,943	8,654,564
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		3,650,229	3,641,000
19	(Less) Accum. Prov. for Depr. and Amort. (122)		24,655	24,655
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	38,582,474	38,311,820
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		54,983,320	53,233,594
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		20,191,500	20,189,628
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		94,621,186	26,197,403
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		212,004,054	141,548,790
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		88,139,126	31,760,949
36	Special Deposits (132-134)		60,437,596	41,080,450
37	Working Fund (135)		2,607,514	5,124,797
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			91,410
40	Customer Accounts Receivable (142)		370,666,115	307,295,202
41	Other Accounts Receivable (143)		326,336,152	115,595,688
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		41,961,715	34,957,745
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		4,043,420	4,603,705
45	Fuel Stock (151)	227	21,182,653	17,117,974
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	131,283,900	111,671,567

49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227	[(a)]221,957	(628)
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	731,067	600,920
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	156,825	1,014,123
55	Gas Stored Underground - Current (164.1)		66,796,355	39,594,587
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		979,449	49,533
57	Prepayments (165)		51,382,582	50,079,311
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		284,014,591	271,606,144
62	Miscellaneous Current and Accrued Assets (174)		3,331,136	2,094,716
63	Derivative Instrument Assets (175)		681,650,782	154,408,115
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		94,621,186	26,197,403
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)		1,957,378,319	1,092,633,415
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		24,172,621	23,861,685
70	Extraordinary Property Losses (182.1)	230a	127,524,176	127,789,135
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	565,039,247	613,483,209
73	Prelim. Survey and Investigation Charges (Electric) (183)		106,872	93,253
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)		137,168	17,943
78	Miscellaneous Deferred Debits (186)	233	284,321,034	216,613,372
79	Def. Losses from Disposition of Utility Plt. (187)		5,741,557	5,741,557
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		33,731,648	35,804,700
82	Accumulated Deferred Income Taxes (190)	234	430,016,445	319,267,771
83	Unrecovered Purchased Gas Costs (191)		(3,536,308)	57,934,878
84	Total Deferred Debits (lines 69 through 83)		1,467,254,460	1,400,607,503
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		14,841,843,375	13,519,625,884

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: OtherMaterialsAndSupplies
This account is for landfill gas pipeline imbalance.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	3,064,096,691	3,014,096,691
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	1,451,424,351	996,139,844
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(13,264,970)	(13,535,624)
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(103,045,030)	(113,138,548)
16	Total Proprietary Capital (lines 2 through 15)		4,871,081,451	4,355,432,772
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	4,823,860,000	4,823,860,000
19	(Less) Reaquired 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)		15,729,451	16,328,252
24	Total Long-Term Debt (lines 18 through 23)		4,808,130,549	4,807,531,748
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		283,782,671	277,813,392
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		88,000	1,920,000
29	Accumulated Provision for Pensions and Benefits (228.3)		(28,709,995)	(10,441,647)
30	Accumulated Miscellaneous Operating Provisions (228.4)		135,051,835	142,404,664
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities		18,366,683	40,964,763
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		205,559,099	205,337,831
35	Total Other Noncurrent Liabilities (lines 26 through 34)		614,138,293	657,999,003
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		357,000,000	140,000,000
38	Accounts Payable (232)		708,906,799	480,600,340
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		291,713	7,330,825
41	Customer Deposits (235)		13,733,533	22,253,544
42	Taxes Accrued (236)	262	116,472,982	133,407,822
43	Interest Accrued (237)		52,169,671	51,831,806
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		3,951,481	1,929,509

48	Miscellaneous Current and Accrued Liabilities (242)		40,266,693	26,338,339
49	Obligations Under Capital Leases-Current (243)		23,509,170	22,139,920
50	Derivative Instrument Liabilities (244)		143,342,442	104,273,341
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		18,366,683	40,964,763
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)		1,441,277,801	949,140,683
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		123,708,753	107,479,955
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)		1,928,264	6,926,248
59	Other Deferred Credits (253)	269	518,347,061	313,123,797
60	Other Regulatory Liabilities (254)	278	891,629,751	916,467,662
61	Unamortized Gain on Reaquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		1,177,028,707	1,189,912,772
64	Accum. Deferred Income Taxes-Other (283)		394,572,745	215,611,244
65	Total Deferred Credits (lines 56 through 64)		3,107,215,281	2,749,521,678
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		14,841,843,375	13,519,625,884

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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

Do not report fourth quarter data in columns (e) and (f)
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.
Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
Use page 122 for important notes regarding the statement of income for any account thereof.
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.
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.
If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
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.
Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
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)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	4,388,121,714	3,831,603,991			3,178,485,486	2,764,186,180	1,209,636,228	1,067,417,811		
3	Operating Expenses											
4	Operation Expenses (401)	320	2,635,508,553	2,079,834,572			1,970,839,868	1,525,854,659	664,668,685	553,979,913		
5	Maintenance Expenses (402)	320	175,029,070	170,368,398			147,385,918	143,511,276	27,643,152	26,857,122		
6	Depreciation Expense (403)	336	524,822,928	500,594,143			374,468,383	361,930,254	150,354,545	138,663,889		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	9,365,324	9,797,122			8,902,654	9,599,069	462,670	198,053		
8	Amort. & Depl. of Utility Plant (404-405)	336	101,835,503	122,988,498			69,876,938	84,047,727	31,958,565	38,940,771		
9	Amort. of Utility Plant Acq. Adj. (406)	336	11,687,828	12,016,844			11,687,828	12,016,844				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		21,846,432	21,846,432			21,846,432	21,846,432				
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		21,725,532	21,419,171			12,725,650	12,419,289	8,999,882	8,999,882		
13	(Less) Regulatory Credits (407.4)		42,514,738	28,070,896			32,370,162	26,419,076	10,144,576	1,651,820		
14	Taxes Other Than Income Taxes (408.1)	262	386,340,822	361,591,022			259,360,685	250,040,104	126,980,137	111,550,918		
15	Income Taxes - Federal (409.1)	262	81,592,777	76,870,089			41,484,612	43,477,587	40,108,165	33,392,502		
16	Income Taxes - Other (409.1)	262	869,191	670,177			869,191	670,177				
17	Provision for Deferred Income Taxes (410.1)	234, 272	465,808,227	233,337,043			264,566,257	157,313,055	201,241,970	76,023,988		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	467,480,717	241,957,595			263,542,456	166,899,178	203,938,261	75,058,417		
19	Investment Tax Credit Adj. - Net (411.4)	266										
20	(Less) Gains from Disp. of Utility Plant (411.6)		5,013,242	6,483,881			5,013,242	6,486,120		(2,239)		

21	Losses from Disp. of Utility Plant (411.7)			(198,954)				(142,578)		(56,376)		
22	(Less) Gains from Disposition of Allowances (411.8)											
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		3,834,848	3,912,946			3,539,560	3,655,310	295,288	257,636		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,925,258,338	3,338,535,131			2,886,628,116	2,426,434,831	1,038,630,222	912,100,300		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		462,863,376	493,068,860			291,857,370	337,751,349	171,006,006	155,317,511		
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)		271,813	934,329								
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		988,707	259,725								
33	Revenues From Nonutility Operations (417)		44,808,060	42,469,398								
34	(Less) Expenses of Nonutility Operations (417.1)		40,561,238	37,327,480								
35	Nonoperating Rental Income (418)											
36	Equity in Earnings of Subsidiary Companies (418.1)	119	270,654	7,223,763								
37	Interest and Dividend Income (419)		(8,731,661)	5,636,780								
38	Allowance for Other Funds Used During Construction (419.1)		28,310,136	27,805,618								
39	Miscellaneous Nonoperating Income (421)		289,517,265	59,116,248								
40	Gain on Disposition of Property (421.1)		235,262	172,334								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		313,131,584	105,771,265								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)											
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		36,800	49,738								
46	Life Insurance (426.2)		(1,759,020)	(1,905,421)								
47	Penalties (426.3)		1,529,387	981,370								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		8,488,691	8,241,911								
49	Other Deductions (426.5)		40,784,988	50,315,731								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		49,080,846	57,683,329								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	681,438	468,920								
53	Income Taxes-Federal (409.2)	262	(67,633)	(26,493,236)								
54	Income Taxes-Other (409.2)	262										

55	Provision for Deferred Inc. Taxes (410.2)	234, 272	(498,795)	(406,133)								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272										
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)		115,010	(26,430,449)								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		263,935,728	74,518,385								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		240,203,334	230,981,897								
63	Amort. of Debt Disc. and Expense (428)		2,651,955	2,535,826								
64	Amortization of Loss on Reaquired Debt (428.1)		2,168,876	2,186,293								
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)		9,268,172	12,562,249								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		18,443,620	16,743,127								
70	Net Interest Charges (Total of lines 62 thru 69)		235,848,717	231,523,138								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		490,950,387	336,064,107								
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)		490,950,387	336,064,107								

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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		961,917,281	865,025,834
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1	Stranded taxes to RE due to tax reform			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	License Hydro Project Excess Earnings		(1,810,100)	(2,090,515)
15	TOTAL Debits to Retained Earnings (Acct. 439)		(1,810,100)	(2,090,515)
16	Balance Transferred from Income (Account 433 less Account 418.1)		490,679,733	328,840,344
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		(35,395,226)	(229,858,382)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(35,395,226)	(229,858,382)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,415,391,688	961,917,281
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)		36,032,663	34,222,563
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		36,032,663	34,222,563
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,451,424,351	996,139,844
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		(13,535,624)	(20,759,387)
50	Equity in Earnings for Year (Credit) (Account 418.1)		270,654	7,223,763
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)		(13,264,970)	(13,535,624)

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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)	490,950,387	336,064,107
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	623,814,810	627,046,435
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of		
5.2	Utility Plant Adjustments	11,687,828	12,016,844
5.3	Property Losses	21,846,432	21,846,432
8	Deferred Income Taxes (Net)	(39,619,118)	(9,026,686)
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	(251,651,225)	(100,240,377)
11	Net (Increase) Decrease in Inventory	(51,304,130)	(4,183,182)
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	227,465,622	129,386,988
14	Net (Increase) Decrease in Other Regulatory Assets	(95,264,559)	(129,708,563)
15	Net Increase (Decrease) in Other Regulatory Liabilities	71,182,691	16,577,484
16	(Less) Allowance for Other Funds Used During Construction	28,310,136	27,805,618
17	(Less) Undistributed Earnings from Subsidiary Companies	270,654	7,223,763
18	Other (provide details in footnote):		
18.1	Other Long-Term Assets	(5,886,051)	(22,518,995)
18.2	Other Long-Term Liabilities	7,902,780	2,979,964
18.3	Conservation Amortization	116,941,715	103,147,450
18.4	Pension Funding	(18,000,000)	(18,000,000)
18.5	Net Unrealized (Gain) Loss on Derivative Transactions	(261,177,050)	(13,784,942)
18.6	Amortization of TCJA Over Collection		(1,191,866)
18.7	IRS PLR		(24,507,486)
18.8	Other	(3,540,771)	9,103,091
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	816,768,571	899,977,317
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,029,123,626)	(936,075,783)
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	(28,310,136)	(27,805,618)
31	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,000,813,490)	(908,270,165)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	20,200	545,785
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		

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	Life Insurance Death Benefit		768,076
53.2	Renewable Energy Credits	(587,046)	53,309
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,001,380,336)	(906,902,995)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		446,062,500
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Investment from Parent	50,000,000	
66	Net Increase in Short-Term Debt (c)	217,000,000	
67	Other (provide details in footnote):		
67.1	Costs related to Debt Issuance or Redemption	(8,458)	(1,354,380)
67.2	Refundable Cash Received for Customer Construction Projects	26,233,489	24,430,007
67.3	Bank Overdraft		1,618
70	Cash Provided by Outside Sources (Total 61 thru 69)	293,225,031	469,139,745
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
78	Net Decrease in Short-Term Debt (c)		(233,800,000)
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(35,395,226)	(229,858,382)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	257,829,805	5,481,363
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)	73,218,040	(1,444,315)
88	Cash and Cash Equivalents at Beginning of Period	77,966,196	79,410,511
90	Cash and Cash Equivalents at End of Period	151,184,236	77,966,196

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

NOTES TO FINANCIAL STATEMENTS

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

(1) Summary of Significant Accounting Policies

Basis of Presentation

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

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

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

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

Utility Plant

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

Planned Major Maintenance

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

Other Property and Investments

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

Depreciation and Amortization

The Company provides for depreciation and amortization on a straight-line basis. Amortization is recorded for intangibles such as regulatory assets and liabilities, computer software and franchises. The annual depreciation provision stated as a percent of a depreciable electric utility plant was 3.4% in 2022 and 2021; depreciable natural gas utility plant was 2.9% and 2.8% in 2022 and 2021, respectively; and depreciable common utility plant was 7.1%, and 6.8% in 2022 and 2021, respectively. The cost of removal is collected from PSE's customers through depreciation expense and any excess is recorded as a regulatory liability.

Tacoma LNG Facility

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, $245.7 million and $239.6 million of plant in service and construction work in progress 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, 2022, and December 31, 2021, 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".

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 AFUDC rate authorized by the Washington Commission for natural gas and electric utility plant additions effective December 19, 2017, was 7.60%. Effective October 1, 2020 for natural gas and October 15, 2020 for electric the authorized AFUDC rate is 7.39%.

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

Revenue Recognition

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

PSE collected Washington State excise taxes (which are a component of general retail customer rates) and municipal taxes totaling $292.8 million and $268.5 million for 2022 and 2021, 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, 2022, and 2021:

Puget Sound Energy

(Dollars in Thousands)	Year Ended December 31,	
Allowance for credit losses:	2022	2021
Beginning balance	$ 34,958	$ 20,080
Provision for credit loss expense[1]	28,316	27,204
Receivables charged-off	(21,312)	(12,326)
Total ending allowance balance	$ 41,962	$ 34,958

[1] $7.1 million and $2.8 million of provision were deferred as cost specific to COVID-19 in 2022 and 2021, 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 deferral of storms under the 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 the approach is used by market participants for these types of assets and liabilities. Accordingly, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

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

On April 12, 2017, PSE entered into a Power Purchase Agreement (PPA) with Skookumchuck Wind Energy Project, LLC (Skookumchuck) in which Skookumchuck would develop a wind generation facility and, once completed, sell bundled energy and associated attributes, namely renewable energy credits to PSE over a term of 20 years. Skookumchuck commenced commercial operation in November 2020. PSE has no equity investment in Skookumchuck but is Skookumchuck's only customer. Based on the terms of the contract, PSE will receive all of the output of the facility, subject to curtailment rights. PSE has concluded that it is not the primary beneficiary of this VIE since it does not control the commercial and operating activities of the facility. Additionally, PSE does not have the obligation to absorb losses or receive benefits. Therefore, PSE will not consolidate the VIE. Purchased energy of $14.6 million was recognized in purchased electricity on the Company's consolidated statements of income for the year ended December 31, 2022 and $1.4 million is included in accounts payable on the Company's consolidated balance sheet for the year ended December 31, 2022. Purchased energy of $19.0 million was recognized in purchased electricity on the Company's consolidated statements of income and $2.7 million included in accounts payable on the Company's consolidated balance sheet for the year ended December 31, 2021.

On May 28, 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, once completed, 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. PSE has no equity investment in Golden Hills but is Golden Hills's only customer. Based on the terms of the contract, PSE will receive all of the output of the facility, subject to curtailment rights. PSE has concluded that Golden Hills is a VIE and that PSE is not the primary beneficiary of this VIE since it does not control the commercial and operating activities of the facility. Additionally, PSE does not have the obligation to absorb losses or receive benefits. Therefore, PSE will not consolidate the VIE. Purchased energy of $18.3 million was recognized in purchased electricity on the Company's consolidated statements of income for the year ended December 31, 2022. There was no balance in accounts payable on the Company's balance sheet as of December 31, 2022.

On February 3, 2021, PSE entered into a PPA with Clearwater Wind Project, LLC (Clearwater) in which Clearwater will develop a wind generation facility on a site located in Rosebud, Custer and Garfield counties, Montana; and, once completed, sell energy and associated attributes to PSE over a term of 25 years. On November 8th, 2022, Clearwater commenced
commercial operations. PSE has no equity investment in Clearwater but is Clearwater's only customer. Based on the terms of the contract, PSE will receive all of the output of the facility, subject to curtailment rights. PSE has concluded that Clearwater is a VIE and that PSE is not the primary beneficiary of this VIE since it does not control the commercial and operating activities of the facility. Additionally, PSE does not have the obligation to absorb losses or receive benefits. Therefore, PSE will not consolidate the VIE. Purchased energy of $5.7 million was recognized in purchased electricity on the Company's consolidated statements of income for the year ended December 31, 2022. Additionally, $2.5 million was included in accounts payable on the Company's balance sheet as of December 31, 2022.

(2) New Accounting Pronouncements

Recently Adopted Accounting Guidance

Reference Rate Reform

In March 2020, the FASB issued 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. The Company has promissory notes that reference LIBOR. As of December 31, 2022, the Company has not utilized any of the expedients discussed within this ASU; however, it continues to assess other agreements to determine if LIBOR is included and if the expedients would be utilized through the allowed period of December 2024.

Fair Value Measurement

In 2018, the FASB issued ASU 2018-13, *"Fair Value Measurement (Topic 820): Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement"*. The amendments in this update modify the disclosure requirements on fair value measurements in Topic 820, Fair Value Measurement, based on the concepts in the Concepts Statement, including the consideration of costs and benefits. The amendments are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. The Company adopted this update as of January 1, 2020, and it impacted Note 11, "Fair Value Measurements". As the amendment contemplates changes in disclosures only, it did not have a material impact on the Company's results of operations, cash flows, or consolidated balance sheets.

(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, 2022, and 2021, are included in the following tables:

Puget Sound Energy (Dollars in Thousands)	Remaining Amortization Period	December 31, 2022	December 31, 2021
Environmental remediation	(a)	$ 141,893	$ 127,977
Storm damage costs electric	3 to 5 years	127,524	127,789
PCA mechanism	N/A	112,207	79,546
Chelan PUD contract initiation	8.8 years	62,611	69,699
Deferred Washington Commission AFUDC	30 years	61,463	62,244
Baker Dam licensing operating and maintenance costs	(b)	55,049	54,525
Get to zero depreciation expense deferral (c)	1 to 4 years	49,605	50,220
Lower Snake River	14.4 years	48,536	53,757
Decoupling deferrals and interest (d)	Less than 2 years	36,773	79,125
Unamortized loss on reacquired debt	1 to 45 years	33,732	35,805
Advanced metering infrastructure	3 years	30,431	23,037
Washington Commission LNG	N/A	25,188	1,764
PGA receivable	2 years	—	57,935
Generation plant major maintenance, excluding Colstrip	3 to 7 years	20,374	12,094
Low Income Program Costs	N/A	17,370	21,755
Property tax tracker	Less than 2 years	12,398	25,896
Energy conservation costs	(a)	10,296	3,573
Washington Commission electric vehicle (c)	4 years	7,796	6,109
Regulatory filing fee deferral	N/A	7,559	—
Snoqualmie licensing operating and maintenance costs	(b)	7,445	7,446
Washington Commission COVID-19	N/A	7,051	3,657
Water heater rental property loss	N/A	5,725	5,725
Mint Farm ownership and operating costs	2.3 years	4,317	6,318
Colstrip major maintenance (c)	3 years	4,035	4,035
Various other regulatory assets	(a)	7,060	32,508
Total PSE regulatory assets		$ 896,438	$ 952,539
Deferred income taxes (e)	N/A	(811,724)	(866,541)
Cost of removal	(f)	(639,320)	(563,129)
PGA unrealized gain	N/A	(287,725)	(60,728)
Repurposed production tax credits	N/A	(133,855)	(134,270)
Decoupling liability	Less than 2 years	(63,206)	(36,506)
Green direct	N/A	(11,837)	(13,194)
Refund on counterparty settlement	1 year	(4,353)	—
PGA liability	2 years	(3,536)	—
Various other regulatory liabilities	(a)	(5,583)	(35,093)
Total PSE regulatory liabilities		(1,961,139)	(1,709,461)
PSE net regulatory assets (liabilities)		$ (1,064,701)	$ (756,922)

(a) *Amortization periods vary depending on 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) *Decoupling deferrals and interest includes a 24 month GAAP reserve of zero and $3.0 million for December 31, 2022 and 2021, respectively.*

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

(f) *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 $639.3 million and $563.1 million in 2022 and 2021, 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 general rate case (GRC) which includes a three-year multiyear rate plan with the Washington Commission on January 31, 2022, requesting an overall increase in electric and natural gas rates of 13.6% and 13.0% respectively in 2023; 2.5% and 2.3%, respectively in 2024; and 1.2% and 1.8%, respectively, in 2025. PSE requested a return on equity of 9.9% in all three rate years. PSE requested an overall rate of return of 7.39% in 2023; 7.44% in 2024; and 7.49% in 2025. The filing requests recovery of forecasted plant additions through 2022 as required by Revised Code of Washington (RCW) 80.28.425 as well as forecasted plant additions through 2025, the final year of the multiyear rate plan.

On January 6, 2023, the Washington Commission approved PSE's natural gas rates in its compliance filing with an overall increase of $70.8 million or 6.4% in 2023 and $19.5 million or 1.65% 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 increase of $247.0 million or 10.75% in 2023 and $33.1 million or 1.33% in 2024 with an effective date of January 11, 2023.

PSE filed a GRC with the Washington Commission on June 20, 2019, requesting an overall increase in electric and natural gas rates of 6.9% and 7.9% respectively. On July 8, 2020, the Washington Commission issued its order on PSE's 2019 GRC. The ruling provided for 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 order also resulted in a combined net increase to electric of $29.5 million, or 1.6%, and to natural gas of $36.5 million, or 4.0%. However, the Washington Commission extended the amortization of certain regulatory assets, PSE's electric decoupling deferral, and PSE's PGA deferral to mitigate the impact of the rate increase in response to the economic uncertainty created by the COVID-19 pandemic. This reduced the electric revenue increase to approximately $0.9 million, or 0.1% and the natural gas increase to $1.3 million, or 0.2% and became effective October 15, 2020 and October 1, 2020, respectively.

In July 2021, PSE received a Private Letter Ruling (PLR) from the IRS which concluded that in the 2019 GRC the Washington Commission's methodology for reversing plant-related excess deferred income taxes was an impermissible methodology under the IRS normalization and consistency rules. The PLR required adjustments to PSE's rates to bring PSE back into compliance with IRS rules. In September 2021, the Washington Commission amended its order in accordance with the PLR. The annualized overall rate impact was an increase of $15.8 million, or 0.7%, for electric and $3.1 million, or 0.3%, for natural gas for a total of $18.9 million with rates effective October 1, 2021. This led to a combined annualized net increase to electric rates of $77.1 million, or 3.7%, an increase of $17.5 million above the $59.6 million granted in the revised final order. The order also led to a combined annualized net increase to natural gas rates of $45.3 million, or 5.9%, an increase of $2.4 million above the $42.9 million granted in the revised final order. The Washington Commission maintained adjustments that mitigated the impacts of the rate increases in response to the economic instability created by the COVID-19 pandemic, which reduced the electric revenue increase to approximately $48.3 million, or 2.3%, and the natural gas increase to $4.9 million, or 0.6%.

Power Cost Only Rate Case

On December 9, 2020, PSE filed its 2020 power cost only rate case (PCORC). The filing proposed an increase of $78.5 million (or an average of approximately 3.7%) in the Company's overall power supply costs with an anticipated effective date in June 2021. On February 2, 2021, PSE supplemented the PCORC to update its power costs, leading to a requested increase from $78.5 million to $88.0 million (or an average of approximately 4.1%).

On March 2, 2021, several of the parties to the PCORC reached a multiparty settlement in principle, which was unopposed. The settlement resulted in an estimated revenue increase of $65.3 million or 3.1%. On June 1, 2021, the Washington Commission issued its Final Order approving and adopting the settlement and authorizing and requiring a power cost update through a compliance filing. On June 17, 2021, PSE filed a compliance filing with the Washington Commission with a revenue increase of $70.9 million or 3.3% due to the update on power costs with rates effective July 1, 2021. Per the

2022 GRC Final Order in Docket No. UE-220066, PCORC rates were set to zero as of January 11, 2023 and PSE agreed not to file a PCORC during 2023 and 2024, the two-year rate plan agreed to in the GRC settlement.

Revenue Decoupling Adjustment Mechanism

On July 8, 2020, the Washington Commission issued the final order in Dockets No. UE-190529 and UG-190530, which instructed PSE to extend the collection of amortization balances for electric decoupling delivery and fixed power cost sections originally filed through the annual May 2020 decoupling filing. The extension requires PSE to move amortization balances for electric decoupling as of August 31, 2020 to be collected from customers for a two-year period, instead of the originally approved one-year period. Additionally, through approving the electric cost of service, the final order approved the re-allocation of decoupling balances from Schedule 40 to the remaining electric decoupling groups.

On December 23, 2020, the Washington Commission approved PSE's filing to update Schedule 142 decoupling amortization rates, with an effective date of January 1, 2021, by zeroing out rates still effective past October 15, 2020 on tariff sheet Schedule 142-H, which was replaced by rates on tariff sheet Schedule 142-I effective October 15, 2020. PSE included a true up of the over-collection amounts for the period of October 15, 2020 through December 31, 2020 in PSE's annual May 2021 decoupling filing.

On June 1, 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. The changes took effect on July 1, 2021.

On September 28, 2021, the Washington Commission approved 2019 GRC filing updated to PLR changes. As part of this filing, the annual electric and 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 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, 2022, PSE performed an analysis to determine if electric and natural gas decoupling revenue deferrals would be collected from customers within 24 months of the annual period, per ASC 980. If not, for GAAP purposes only, PSE would need to record a reserve against the decoupling revenue and regulatory asset balance. Once the reserve is probable of collection within 24 months from the end of the annual period, the reserve can be recognized as decoupling revenue. The analysis indicated that electric and natural gas deferred revenue will be collected within 24 months of the annual period; therefore no reserve adjustment was booked to 2022 electric and natural gas decoupling revenue. This compares to $3.0 million of electric deferred revenue not being collected within 24 months of the annual period in 2021; therefore, a reserve adjustment was booked to 2021 electric decoupling revenue. Natural gas deferred revenue would be collected within 24 months of the annual period; therefore no reserve adjustment was booked to 2021 natural gas decoupling revenue.

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:

	Company's Share		Customers' Share	
Annual Power Cost Variability	Over	Under	Over	Under
Over or Under Collected by up to $17 million	100%	100%	—%	—%
Over or Under Collected by 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, 2022, in its PCA mechanism, PSE under recovered its allowable costs by $110.1 million of which $74.6 million was apportioned to customers and $1.5 million of interest was accrued on the deferred customer balance. This compares to an under recovery of allowable costs of $68.0 million, for the year ended December 31, 2021, of which $36.7 million was apportioned to customers and accrued $1.7 million of interest on the total deferred customer balance.

Power Cost Adjustment Clause

On July 8, 2020, the Washington Commission issued the final order in Dockets No. UE-190529 and UG-190530, which instructed PSE to remove Schedule 95 collection on decoupling allowed rates for Special Contracts, which are included in allowed rates under the Decoupling Schedule 142 effective October 15, 2020.

PSE exceeded the $20.0 million cumulative deferral balance in its PCA mechanism in 2020. The surcharging of deferrals can be triggered by the Company when the balance in the deferral account is a credit of $20.0 million or more. During 2020, actual power costs were higher than baseline power costs; thereby, creating an under-recovery of $76.1 million. Under the terms of the PCA's sharing mechanism for under-recovered power costs, PSE absorbed $32.1 million of the under-recovered amount, and customers were responsible for the remaining $44.0 million, or $46.0 million including interest. PSE filed to recover the deferred balance in Docket No. UE-210300, and the Washington Commission allowed the recovery effective December 1, 2021.

Additionally, PSE exceeded the $20.0 million cumulative deferral balance in its PCA mechanism in 2021. During 2021, actual power costs were higher than baseline power costs, thereby creating an under-recovery of $68.0 million. Under the terms of the PCA's sharing mechanism for under-recovered power costs, 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. On October 27, 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.

Purchased Gas Adjustment Mechanism

On October 28, 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.

On October 27, 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.

On November 15, 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.

The following table presents the PGA mechanism balances and activity at December 31, 2022 and December 31, 2021:

Puget Sound Energy		
(Dollars in Thousands)	At December 31,	At December 31,
PGA receivable balance and activity	2022	2021
PGA receivable beginning balance	$ 57,935	$ 87,655
Actual natural gas costs	457,950	364,775
Allowed PGA recovery	(496,879)	(396,236)
Interest	1,674	1,741
Refund from counterparty settlement	(24,216)	—
PGA (liability)/receivable ending balance	$ (3,536)	$ 57,935

Get to Zero Depreciation Deferral

On April 10, 2019, PSE filed an accounting petition with the Washington Commission, requesting authorization to defer depreciation expense associated with Get To Zero (GTZ) projects that were placed in service after June 30, 2018. The GTZ project consists of a number of short-lived technology upgrades. The depreciation expense associated with the GTZ projects with lives of 10 years or less that were placed in service after June 30, 2018, were deferred beginning May 1 per the petition request. For the year ended December 31, 2022 and December 31, 2021, PSE deferred $11.8 million and $6.6 million of depreciation expense for GTZ, respectively. In addition to the deferral of depreciation expense, PSE had also requested to defer carrying charges on the GTZ deferral, to be calculated utilizing the FERC quarterly rate of return. The 2022 GRC final order authorized recovery of all remaining GTZ depreciation and carrying charge balances as of December 2022. Finally, all GTZ deferrals ended as of December 2022.

Crisis Affected Customer Assistance Program

On April 6, 2020, PSE filed with the Washington Commission revisions to its currently effective electric and natural gas service tariffs. The purpose of this filing was to incorporate into PSE's low-income tariff a new temporary bill assistance program, Crisis Affected Customer Assistance Program (CACAP-1) (Dockets No. UE-200331 and UG-200332), to mitigate the economic impact of the COVID-19 pandemic on PSE's customers. CACAP-1 allowed PSE customers facing financial hardship due to COVID-19 to receive up to $1,000 in bill assistance. The program made available $11.0 million in unspent low income funds from prior years, therefore resulting in no rate impact, and supplemented other forms of financial assistance. CACAP-1 ran from April 13, 2020, to September 30, 2020.

On March 28, 2021, the Washington Commission approved PSE's CACAP-2 (Dockets No. UE-210137 and UG-210138). With a program budget of $20.0 million for electric customers and $7.7 million for natural gas customers, CACAP-2, which ran from April 12, 2021, to March 29, 2022, provided up to $2,500 per year in bill assistance for arrearages for each qualifying low-income household.

On October 15, 2021, PSE submitted for the Washington Commission's review and approval a Supplemental CACAP (Dockets No UE-210792 and UG-210793) filing to continue assistance for PSE customers facing financial hardship due to COVID-19. The Washington Commission approved the Supplemental CACAP program to be effective on November 15, 2021. The Supplemental CACAP utilized carry-over funds not expended in any prior years under PSE's Schedule 129 Home Energy Lifeline Program (HELP), with a combined total budget of $34.5 million for both electric and natural gas residential

customers (capped at $23.7 million and $10.8 million, respectively). Supplemental CACAP benefits offered to cover a qualifying residential customer's past due balance, up to $2,500. PSE applied the Supplemental CACAP benefits automatically, with an opt-out option, in December 2021.

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, 2022, PSE incurred $32.2 million in weather-related electric transmission and distribution system restoration costs, 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. This compares to $51.4 million incurred in weather-related electric transmission and distribution system restoration costs for the year ended December 31, 2021, of which the Company deferred $40.9 million and $0.2 million as regulatory assets related to storms that occurred in 2021 and 2020, 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 the federal, state and local authorities and is required to undertake certain environmental investigative and remedial efforts as a result of these laws and regulations. The Company has been named by the Environmental Protection Agency (EPA), the Washington State Department of Ecology and/or other third parties as potentially responsible at several contaminated sites and 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. Management believes it is probable and reasonably estimable that the impact of the potential outcomes of disputes with certain property owners and other potentially responsible parties will result in environmental remediation costs of $84.4 million for natural gas and $48.3 million for electric. The Company believes a significant portion of its past and future environmental remediation costs are recoverable from insurance companies, from third parties or from customers under a Washington Commission order. The Company is also subject to cost-sharing agreements with third parties regarding environmental remediation projects in Seattle, Tacoma, Everett, and Bellingham, Washington.

As of December 31, 2022, the Company's share of future remediation costs is estimated to be approximately $61.5 million. The Company's deferred electric environmental costs are $51.5 million and $52.2 million at December 31, 2022 and 2021, respectively, net of insurance proceeds. The Company's deferred natural gas environmental costs are $90.4 million and $75.8 million at December 31, 2022 and 2021, respectively, net of insurance proceeds.

(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, 2022, approximately $1.4 billion of unrestricted retained earnings was available for the payment of dividends under the most restrictive mortgage indenture covenant.

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, 2022, and the EBITDA to interest expense was 5.0 to 1.0 for the twelve months ended December 31, 2022.

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, 2022, 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:

		Puget Sound Energy	
Utility Plant	Estimated Useful Life[1]	December 31,	
(Dollars in Thousands)	(Years)	2022	2021
Distribution plant	7-65	$ 9,406,017	$ 9,026,042
Production plant	3-90	3,780,910	3,815,599
Transmission plant	44-75	1,683,737	1,663,559
General plant	5-75	760,094	773,662
Intangible plant (including capitalized software)[2]	3-50	745,973	788,240
Plant acquisition adjustment	N/A	282,792	282,792
Underground storage	25-60	58,716	56,820
Liquefied natural gas storage	25-50	14,498	14,498
Plant held for future use	N/A	46,232	46,172
Recoverable Cushion Gas	N/A	8,784	8,655
Plant not classified	N/A	723,383	316,933
Finance leases, net of accumulated amortization[3]	N/A	99,967	105,020
Less: accumulated provision for depreciation		(6,688,033)	(6,416,246)
Subtotal		$ 10,923,070	$ 10,481,746
Construction work in progress		861,801	870,204
Net utility plant		$ 11,784,871	$ 11,351,950

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, 2022, and 2021, accumulated amortization of finance leases at PSE was $7.3 million and $2.6 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 tables indicate the Company's percentage ownership and the extent of the Company's investment in jointly owned generating plants in service at December 31, 2022. 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 %	$ 579,019	$ —	$ (434,099)
Frederickson 1	Natural Gas	49.85	69,415	—	(27,962)
Jackson Prairie	Natural Gas	33.34	58,716	837	(26,186)
Tacoma LNG	Natural Gas	various	245,690	503	(5,052)

In June 2019, Talen, the plant operator of Colstrip Units 1 and 2, announced a plan to shut down as of December 31, 2019. The Company retired Colstrip 1&2 from Utility Plant and transferred the unrecovered plant amount of $126.5 million to regulatory assets, offset by depreciation as included in base rates until the 2019 GRC became effective in October 2020. Consistent with the GRC settlement in 2017, monetization of the PTCs will fund the following: (i) Colstrip Community Transition Fund, (ii) unrecovered Colstrip plant and (iii) incurred decommissioning and remediation costs for Colstrip. At December 31, 2022, and December 31, 2021, the unrecovered plant for Colstrip 1&2 was fully offset with PTCs.

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 accounting criteria were not met as of December 31, 2022. As such, Colstrip Units 3 and 4 are classified as Electric Utility Plant on the Company's balance sheet as of December 31, 2022.

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, 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, 2021, the Company reviewed the estimated remediation costs at Colstrip and decreased the Colstrip ARO liability by $1.5 million for Colstrip Units 1 and 2, and $3.1 million for Colstrip Units 3 and 4. The 2021 decrease to Colstrip 1 and 2 is primarily due to remediation plans approved by the Montana Department of Environmental Quality under a 2012 settlement between the plant operator and the state for the remaining sites at Colstrip. The plant operator previously contested the approved plan for Colstrip Units 1 and 2 under the defined process in the settlement with the state and reached a settlement agreement regarding the ability to still present another option under the settlement terms and conditions. The Company had previously recorded these incremental costs in 2020 for remediation work on the older ponds under ASC 410-20 "Asset Retirement and Environmental Obligations" and ASC 410-30 "Environmental Remediation". For the twelve months ended December 31, 2022 and 2021, the Company also recorded relief of ARO and environmental remediation liability of $6.9 million and $13.1 million, respectively.

In addition, the Company recorded Tacoma LNG facility ARO liability of $3.9 million and $3.8 million for PSE as of December 31, 2022 and December 31, 2021, respectively. The 2022 and 2021 increases to the Tacoma LNG facility ARO liabilities are primarily due to continued construction of the plant. In 2022, the ARO liability associated with the Tacoma LNG facility was fully recorded as construction was essentially complete and commissioning activities are on-going.

Puget Sound Energy	December 31,	
(Dollars in Thousands)	2022	2021
Asset retirement obligation at beginning of the period	$ 205,338	$ 208,745
Relief of liability	(6,867)	(13,145)
Revisions in estimated cash flows	1,519	3,948
Accretion expense	5,569	5,790
Asset retirement obligation at end of period	$ 205,559	$ 205,338

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, 2022:

- 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.

(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 2022 and 2021:

(Dollars in Thousands)			December 31,	
Series	Type	Due	2022	2021
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
*	Debt discount, issuance cost and other	*	(37,095)	(39,141)
Total PSE long-term debt			$ 4,786,765	$ 4,784,719

* *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, 2022, 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

On September 15, 2021, PSE issued $450.0 million of senior secured notes at an interest rate of 2.893%. The notes were issued for a period of 30 years, mature on September 15, 2051, and pay interest semi-annually on March 15 and September 15 of each year. The proceeds from the issuance will be used for repayment of commercial paper as well as general corporate purposes.

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, $1.4 billion was available to be issued. The shelf registration will expire in August 2025.

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)	2023	2024	2025	2026	2027	Thereafter	Total
Maturities of:							
PSE	$ —	$ —	$ 17,000	$ —	$ 300,000	$ 4,506,860	$ 4,823,860
Total long-term debt	$ —	$ —	$ 17,000	$ —	$ 300,000	$ 4,506,860	$ 4,823,860

(7) Liquidity Facilities and Other Financing Arrangements

As of December 31, 2022, and 2021, PSE had $357.0 million and $140.0 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 2022 and 2021 was 6.1% and 1.6%, respectively. As of December 31, 2022, PSE had several committed credit facilities that are described below.

Puget Sound Energy

Credit Facility

On May 16, 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) is being discontinued in 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% or less at all times. PSE certifies its compliance with such covenants to participating banks each quarter. As of December 31, 2022, 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, 2022, no amount was drawn under PSE's credit facility and $357.0 million was outstanding under the commercial paper program. Outside of the credit agreement, PSE had a $2.3 million letter of credit in support of a long-term transmission contract and had $28.0 million issued under a standby letter of credit in support of natural gas purchases.

Demand Promissory Note

In 2006, PSE entered into a revolving credit facility with Puget Energy, in the form of a credit agreement and a demand promissory note pursuant to which PSE may borrow up to $30.0 million from Puget Energy subject to approval by Puget Energy. Under the terms of the promissory note, PSE pays interest on the outstanding borrowings based on the lower of the weighted-average interest rates of PSE's outstanding commercial paper or PSE's senior unsecured revolving credit facility. Absent such borrowings, interest is charged at one-month LIBOR plus 0.25%. As of December 31, 2022, there was no outstanding balance under the promissory note.

(8) Leases

During 2021, mechanical completion was achieved for the Puget LNG facility which triggered an increase in the lease payments for the Port of Tacoma lease. This remeasurement resulted in an increase of the operating lease ROU asset and operating lease liabilities of $26.3 million, of which $0.4 million was recorded in current operating lease liabilities and $25.9 million was recorded in operating lease liabilities. Additionally, two finance leases commenced for service center facilities in Kent and Puyallup, Washington. The Kent lease has a term of 20 years and resulted in an increase of electric utility plant and finance lease liabilities of $45.1 million, of which $1.0 million was recorded in other current liabilities and $44.1 million was recorded in finance lease liabilities, respectively. The Puyallup lease has a term of 20 years and resulted in an increase in common utility plant and finance lease liabilities of $61.3 million, of which $0.4 million was recorded in other current liabilities and $59.9 million was recorded in finance lease liabilities.

During 2022, there were no material changes regarding the Company's leases.

The components of lease cost were as follows:

Puget Sound Energy (Dollars in Thousands)	Year Ended December 31, 2022	Year Ended December 31, 2021
Finance lease cost:		
Amortization of right-of-use asset	$ 2,465	$ 1,291
Interest on lease liabilities	2,482	358
Total finance lease cost	$ 4,947	$ 1,649
Operating lease cost	$ 22,471	$ 22,568

Supplemental cash flow information related to leases was as follows:

Puget Sound Energy (Dollars in Thousands)	Year Ended December 31, 2022	Year Ended December 31, 2021
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flow for operating leases	$ 16,574	$ 16,440
Investing cash flow for operating leases	5,896	6,143
Operating cash flow for finance leases	2,482	358
Financing cash flow for finance leases	2,465	1,291
Non-cash disclosure upon commencement of new lease		
Right-of-use assets obtained in exchange for new operating lease liabilities	$ 5,338	$ 4,820
Right-of-use assets obtained in exchange for new finance lease liabilities	—	105,176
Non-cash disclosure upon modification of existing lease		
Modification of operating lease right-of-use assets	$ 21,068	$ 26,287

Supplemental balance sheet information related to leases was as follows:

Puget Sound Energy (Dollars in Thousands) **Operating Leases**	At December 31, 2022	At December 31, 2021
Operating lease right-of-use asset	$ 193,509	$ 184,957
Operating leases liabilities current	$ 20,342	$ 20,398
Operating lease liabilities long-term	181,265	172,510
Total operating lease liabilities	$ 201,607	$ 192,908
Finance Leases		
Common plant	$ 58,391	$ 61,227
Electric plant	41,576	43,793
Total finance lease assets	$ 99,967	$ 105,020
Other current liabilities	$ 3,167	$ 1,742
Finance lease liabilities	102,518	105,303
Total finance lease liabilities	$ 105,685	$ 107,045
Weighted Average Remaining Lease Term		
Operating leases	22.00 Years	22.80 Years
Finance leases	19.10 Years	20.15 Years

Weighted Average Discount Rate		
Operating leases	3.62 %	3.27 %
Finance leases	3.07 %	3.07 %

The following table summarizes the Company's estimated future minimum lease payments as of December 31, 2022:

Maturities of lease liabilities	Future Minimum Lease Payments	
(Dollars in Thousands)		
At December 31,	Operating Leases	Finance Leases
2023	$ 23,676	$ 6,383
2024	23,232	6,408
2025	21,887	6,534
2026	21,472	6,591
2027	21,047	6,670
Thereafter	172,969	109,882
Total lease payments	$ 284,283	$ 142,468
Less imputed interest	(82,676)	(36,783)
Total net present value	$ 201,607	$ 105,685

(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 Power Cost Adjustment. 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	Year Ended December 31,					
(Dollars in Thousands)	Volumes (millions)		Assets[1]		Liabilities[2]	
	2022	2021	2022	2021	2022	2021
Electric portfolio derivatives	*	*	$ 337,703	$ 74,829	$ 87,120	$ 85,424
Natural gas derivatives (MMBtus)[3]	322	347	343,947	79,578	56,222	18,850
Total derivative contracts			$ 681,650	$ 154,407	$ 143,342	$ 104,274
Current			587,029	128,210	124,976	63,309
Long-term			94,621	26,197	18,366	40,965
Total derivative contracts			$ 681,650	$ 154,407	$ 143,342	$ 104,274

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 234.9 million One Million British Thermal Units (MMBtus) and purchased electricity of 5.3 million megawatt hours (MWhs) at December 31, 2022, and 238.0 million MMBtus and 8.1 million MWhs at December 31, 2021.*

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, 2022						
(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	Gross Amounts Not Offset 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

Puget Sound Energy

December 31, 2021						
(Dollars in Thousands)	Gross Amount Recognized[1]	Gross Amounts Offset in the Consolidated Balance Sheet	Net of Amounts Presented in the Consolidated Balance Sheet	Gross Amounts Not Offset in the Consolidated Balance Sheet		
				Commodity Contracts[2]	Cash Collateral Received/Pledged	Net Amount
Assets:						
Energy derivative contracts	$ 154,407	$ —	$ 154,407	$ (40,833)	$ —	$ 113,574
Liabilities:						
Energy derivative contracts	104,274	—	104,274	(40,833)	(1,743)	$ 61,698

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	2022	2021
Gas for Power Derivatives:			
Unrealized	Unrealized gain (loss) on derivative instruments, net	61,761	26,686
Realized	Electric generation fuel	158,550	76,504
Power Derivatives:			
Unrealized	Unrealized gain (loss) on derivative instruments, net	199,416	(12,901)
Realized	Purchased electricity	20,917	(3,044)
Total gain (loss) recognized in income on derivatives		$ 440,644	$ 87,245

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, 2022, approximately 99.4% 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 0.6% 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, 2022, 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, 2022, PSE had cash posted as collateral of $23.2 million related to contracts executed on the ICE platform. In August 2022, PSE entered into a standby letter of credit agreement with TD Bank allowing standby letter of into a standby letter of credit agreement with TD Bank allowing standby letter of

credit postings of up to $50.0 million as a condition of transacting on the ICE NGX platform. As of December 31, 2022, PSE had $33.0 million in cash posted with ICE NGX and $28.0 million issued under the standby letter of credit agreement. 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, 2022.

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 (Dollars in Thousands)	December 31, 2022			December 31, 2021		
Contingent Feature	Fair Value[1] Liability	Posted Collateral	Contingent Collateral	Fair Value[1] Liability	Posted Collateral	Contingent Collateral
Credit rating[2]	$ 3,157	$ —	$ 3,157	$ 52,537	$ —	$ 52,537
Requested credit for adequate assurance	4,157	—	—	9,380	—	—
Forward value of contract[3]	5,661	56,200	N/A	1,743	12,782	N/A
Total	$ 12,975	$ 56,200	$ 3,157	$ 63,660	$ 12,782	$ 52,537

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 $55.0 million and $53.2 million at December 31, 2022, and 2021, 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, 2022		December 31, 2021	
(Dollars in Thousands)	Level	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial liabilities:					
Long-term debt (fixed-rate), net of discount[1]	2	$ 4,786,765	$ 4,379,010	$ 4,784,719	$ 6,145,639
Total		$ 4,786,765	$ 4,379,010	$ 4,784,719	$ 6,145,639

1. The carrying value includes debt issuances costs of $21.4 million and $22.8 million for December 31, 2022, and 2021, 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, 2022			Fair Value December 31, 2021		
(Dollars in Thousands)	Level 2	Level 3	Total	Level 2	Level 3	Total
Assets:						
Electric derivative instruments	$ 218,610	$ 119,093	$ 337,703	$ 68,011	$ 6,818	$ 74,829
Gas derivative instruments	342,988	959	343,947	79,526	52	79,578
Total derivative assets	$ 561,598	$ 120,052	$ 681,650	$ 147,537	$ 6,870	$ 154,407
Liabilities:						
Electric derivative instruments	$ 84,105	$ 3,015	$ 87,120	$ 35,854	$ 49,570	$ 85,424
Gas derivative instruments	55,136	1,086	56,222	16,678	2,172	18,850
Total derivative liabilities	$ 139,241	$ 4,101	$ 143,342	$ 52,532	$ 51,742	$ 104,274

Puget Sound Energy Level 3 Roll-Forward Net Asset(Liability)	Year Ended December 31, 2022			Year Ended December 31, 2021		
(Dollars in Thousands)	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Balance at beginning of period	$ (42,752)	$ (2,120)	$ (44,872)	$ (23,718)	$ (1,135)	$ (24,853)
Changes during period						
Realized and unrealized energy derivatives:						
Included in earnings[1]	180,533	—	180,533	(15,839)	—	(15,839)
Included in regulatory assets / liabilities	—	301	301	—	(1,749)	(1,749)
Settlements[2]	(21,972)	1,369	(20,603)	(3,195)	764	(2,431)
Transferred into Level 3	—	—	—	—	—	—
Transferred out Level 3	269	323	592	—	—	—
Balance at end of period	$ 116,078	$ (127)	$ 115,951	$ (42,752)	$ (2,120)	$ (44,872)

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 $147.1 million and $(21.6) million for the years ended December 31, 2022 and 2021, 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, 2022 and 2021. 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, 2022:

Puget Sound Energy	Fair Value				Range		
(Dollars in Thousands)	Assets[1]	Liabilities[1]	Valuation Technique	Unobservable Input	Low	High	Weighted
Electricity	$ 119,093	$ 3,015	Discounted cash flow	Power Prices (per MWh)	$ 55.79	$ 291.03	$ 131.51
Natural Gas	$ 959	$ 1,086	Discounted cash flow	Natural Gas Prices (per MMBtu)	$ 3.84	$ 7.00	$ 4.87

1.

[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, 2022, 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 $37.6 million.

(11) Employee Investment Plans

The Company's Investment Plan is a qualified employee 401(k) plan, under which employee salary deferrals and after-tax contributions are used to purchase several different investment fund options. PSE's contributions to the employee Investment Plan were $25.2 million and $23.6 million for the years 2022 and 2021, 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: For 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 play 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. These benefits are provided principally through an insurance company. The insurance premiums, paid primarily by retirees, are based on the benefits provided during the prior year. On June 11, 2019, the Company's Welfare Benefits Committee approved the termination of the Plan effective December 31, 2019, and the creation of a Retiree Health Reimbursement Account (HRA) Plan effective January 1, 2020.

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, 2022, and 2021:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 834,960	$ 849,383	$ 43,155	$ 46,742	$ 11,654	$ 12,114
Amendments	—	—	—	—	38	205
Service cost	26,351	26,888	557	456	217	155
Interest cost	24,263	22,381	1,253	1,183	311	302
Actuarial loss (gain)	(215,005)	(6,826)	(5,260)	828	(2,397)	(514)
Benefits paid	(80,226)	(55,831)	(7,659)	(6,054)	(808)	(803)
Medicare part D subsidy received	—	—	—	—	—	195
Administrative expense	(1,065)	(1,035)	—	—	—	—
Benefit obligation at end of period	$ 589,278	$ 834,960	$ 32,046	$ 43,155	$ 9,015	$ 11,654

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 898,550	$ 834,655	$ —	$ —	$ 6,341	$ 5,918
Actual return on plan assets	(176,537)	102,787	—	—	(550)	1,005
Employer contribution	18,000	18,000	7,659	6,054	207	222
Benefits paid	(80,226)	(55,831)	(7,659)	(6,054)	(808)	(804)
Administrative expense	(1,254)	(1,061)	—	—	—	—
Fair value of plan assets at end of period	$ 658,533	$ 898,550	$ —	$ —	$ 5,190	$ 6,341
Funded status at end of period	$ 69,255	$ 63,590	$ (32,046)	$ (43,155)	$ (3,825)	$ (5,313)

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Amounts recognized in Consolidated Balance Sheet consist of:						
Noncurrent assets	$ 69,255	$ 63,590	$ —	$ —	$ —	$ —
Current liabilities	—	—	(3,532)	(2,822)	(252)	(280)
Noncurrent liabilities	—	—	(28,514)	(40,333)	(3,573)	(5,033)
Net assets (liabilities)	$ 69,255	$ 63,590	$ (32,046)	$ (43,155)	$ (3,825)	$ (5,313)

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Change in plan obligation and plan asset:						
Projected benefit obligation	$ 589,278	$ 834,960	$ 32,046	$ 43,155	$ 9,015	$ 11,654
Accumulated benefit obligation	582,538	823,418	29,763	40,773	8,929	11,549
Fair value of plan assets	658,533	898,550	—	—	5,190	6,341

The following tables summarize PSE's pension benefit amounts recognized in accumulated other comprehensive income (AOCI) for the years ended December 31, 2022, and 2021:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Amounts recognized in Accumulated Other Comprehensive Income consist of:						
Net loss (gain)	$ 124,767	$ 127,111	$ 1,864	$ 10,103	$ (2,056)	$ (622)
Prior service cost (credit)	—	—	289	578	258	242
Total	$ 124,767	$ 127,111	$ 2,153	$ 10,681	$ (1,798)	$ (380)

The following table summarizes PSE's net periodic benefit cost for the years ended December 31, 2022 and 2021:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Components of net periodic benefit cost:						
Service cost	$ 26,351	$ 26,888	$ 557	$ 456	$ 217	$ 155
Interest cost	24,263	22,381	1,253	1,183	311	302
Expected return on plan assets	(51,016)	(48,242)	—	—	(379)	(355)
Amortization of prior service cost (credit)	—	(1,513)	289	349	22	6
Amortization of net loss (gain)	15,080	21,862	2,648	2,344	(35)	(52)
Net periodic benefit cost	$ 14,678	$ 21,376	$ 4,747	$ 4,332	$ 136	$ 56

The following table summarizes PSE's benefit obligations recognized in other comprehensive income (OCI) for the years ended December 31, 2022 and 2021:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2022	2021	2022	2021	2022	2021
Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:						

Net loss (gain)	$ 12,736	$ (61,345)	$ (5,260)	$ 828	$ (1,468)	$ (1,164)
Amortization of net (loss) gain	(15,080)	(21,862)	(2,648)	(2,343)	35	53
Settlements, mergers, sales, and closures	—	—	(331)	(886)	—	—
Prior service cost (credit)	—	—	—	—	38	205
Amortization of prior service (cost) credit	—	1,513	(289)	(349)	(22)	(6)
Total change in other comprehensive income for year	$ (2,344)	$ (81,694)	$ (8,528)	$ (2,750)	$ (1,417)	$ (912)

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, 2023, are expected to be at least $18.0 million, $3.5 million and $0.3 million, respectively.

Assumptions

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

	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
Benefit Obligation Assumptions	2022	2021	2022	2021	2022	2021
Discount rate	5.60%	3.00%	5.60%	3.00%	5.60%	3.00%
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
Benefit Cost Assumptions						
Discount rate	3.00	2.70	3.00	2.70	3.00	2.70
Return on plan assets	6.50	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 gain of $215.0 million in 2022. This is primarily due to the increase in the discount rate used in measuring the 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)	2023	2024	2025	2026	2027	2028-2032
Qualified Pension total benefits	$ 46,500	$ 47,800	$ 48,700	$ 49,900	$ 50,700	$ 260,700
SERP Pension total benefits	3,532	1,844	7,634	2,271	10,956	7,479
Other Benefits total	912	890	881	879	854	3,829

Plan Assets

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

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

The Retirement Plan Committee invests trust assets with investment managers who have historically achieved above-median long-term investment performance within the risk and asset allocation limits that have been established. Interim evaluations are routinely performed with the assistance of an outside investment consultant.

To obtain the desired return needed to fund the pension benefit plans, the Retirement Plan Committee has established investment allocation percentages by asset classes as follows:

	Allocation		
Asset Class	Minimum	Target	Maximum
Domestic large cap equity	25 %	31 %	40 %
Domestic small cap equity	—	9	15
Non-U.S. equity	10	25	30
Fixed income	25	35	40
Real estate	—	—	10
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, 2022, and 2021:

	Recurring Fair Value Measures December 31, 2022				Recurring Fair Value Measures December 31, 2021			
(Dollars in Thousands)	Level 1	Level 2	Other	Total	Level 1	Level 2	Other	Total
Assets:								
Common Stock								
– Domestic	$175,969	$298	$—	$176,267	$249,021	$99	$—	$249,120
– Foreign	17,767	—	—	17,767	25,963	—	—	25,963
Government Securities	61,693	8,828	—	70,521	65,266	2,470	—	67,736
Corporate Securities								
– Domestic	—	16,005	—	16,005	—	12,820	—	12,820
– Foreign	—	6,525	—	6,525	—	5,239	—	5,239
Cash and cash equivalents	4,678	(632)	—	4,046	3,638	(540)	—	3,098
Investments measured at NAV								
- Collective Investment Funds	—	—	262,910	262,910	—	—	359,861	359,861
- Partnership	—	—	86,827	86,827	—	—	115,570	115,570
- Mutual Funds	—	—	46,005	46,005	—	—	80,724	80,724
- Other	—	—	846	846	—	—	1,434	1,434
Net (payable) receivable	—	—	(29,186)	(29,186)	—	—	(23,015)	(23,015)
Total assets	$260,107	$31,024	$367,402	$658,533	$343,888	$20,088	$534,574	$898,550

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 December 31, 2022				Recurring Fair Value Measures December 31, 2021			
(Dollars in Thousands)	Level 1	Level 2	Other	Total	Level 1	Level 2	Other	Total
Assets:								
Money markets	$ —	$ —	$ —	$ —	$ 4	$ —	$ —	$ 4
Mutual fund	—	5,190	—	5,190	—	6,337	—	6,337
Net (payable) receivable	—	—	—	—	—	—	—	—
Total assets	$ —	$ 5,190	$ —	$ 5,190	$ 4	$ 6,337	$ —	$ 6,341

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 unadjusted 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)	2022	2021
Charged to operating expenses:		
Current:		
Federal	$ 81,597	$ 52,616
State	869	670
Deferred:		
Federal	(2,243)	(11,266)
State	—	—
Total income tax expense	$ 80,223	$ 42,020

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)	2022	2021
Income taxes at the statutory rate	$ 119,962	$ 79,868
Increase (decrease):		
Utility plant differences[1]	$ (23,028)	$ (22,325)
AFUDC, net	(3,567)	1,509
Executive Compensation	1,821	1,386
Treasury grant amortization	(5,717)	(5,424)
Tax reform	(13,722)	(13,392)
Other–net	4,474	398
Total income tax expense	$ 80,223	$ 42,020
Effective tax rate	14.0 %	11.0 %

1. Utility plant differences include the reversal of excess deferred taxes using the average rate assumption method in the amount of $27.2 million and $27.6 million in 2022 and 2021, respectively.

The Company's net deferred tax liability at December 31, 2022, and 2021, is composed of amounts related to the following types of temporary differences:

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2022	2021
Utility plant and equipment	$ 1,852,644	$ 1,892,674
Unrealized gain on derivative instruments	143,147	31,940
Other deferred tax liabilities	281,593	227,806
Subtotal deferred tax liabilities	2,277,384	2,152,420
Net regulatory liability for income taxes	(811,724)	(866,541)
Other deferred tax assets	(293,977)	(178,211)
Unrealized loss on derivative instruments	(30,102)	(21,412)
Subtotal deferred tax assets	(1,135,803)	(1,066,164)
Total net deferred tax liabilities	$ 1,141,581	$ 1,086,256

The Company calculates its deferred tax assets and liabilities under ASC 740, "Income Taxes" (ASC 740). ASC 740 requires recording deferred tax balances, at the currently enacted tax rate, on assets and liabilities that are reported differently for income tax purposes than for financial reporting purposes. The utilization of deferred tax assets requires sufficient taxable income in future years. ASC 740 requires a valuation allowance on deferred tax assets when it is more likely than not that the deferred tax assets will not be realized. PSE fully utilized its PTC balance in 2021 and had no carryforwards at the end of 2021. Net operating losses generated in 2018 and thereafter have no expiration date. No valuation allowance has been provided for net operating loss carryforwards.

Unrecognized Tax Benefits

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

As of December 31, 2022, and 2021, 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 2019 through 2022. 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. 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 accounting criteria were not met as of December 31, 2022. As such, Colstrip Units 3 and 4 are classified as Electric Utility Plant on the Company's balance sheet as of December 31, 2022.

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.

On May 19, 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 October 13, 2021, the United States District Court for the District of Montana issued a preliminary injunction finding it likely that Senate Bill 266 unconstitutionally violates the Commerce Clause and Contract Clause of the United States Constitution. Since then, a motion for summary judgment was filed requesting a permanent injunction against enforcement of Senate Bill 266. On September 29, 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. On October 18, 2022, the U.S. District Court Judge accepted in full the magistrate judge recommendation for a permanent injunction against enforcement of Senate Bill 266.

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.

(15) Commitments and Contingencies

For the year ended December 31, 2022, approximately 16.4% of the Company's energy output was obtained at an average cost of approximately $0.034 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)	2022	2021
PUD contract costs	$ 149,575	$ 117,812

As of December 31, 2022, the Company purchased portions of the power output of the PUDs' projects as set forth in the following table:

		Company's Current Share of					
(Dollars in Thousands)	Contract Expiration	2023 Percent of Output	2023 Megawatt Capacity	Estimated 2023 Total Costs	2023 Debt Service Costs	Interest included in 2023 Debt Service Costs	Debt Outstanding
Chelan County PUD[1]:							
Rock Island Project	2031	30.0 %	187	$ 47,892	$ 12,072	$ 5,132	$ 93,493
Rocky Reach Project	2031	30.0	390	54,022	5,039	1,907	33,757
Douglas County PUD[2]:							
Wells Project	2028	32.8	276	45,489	—	—	—
Grant County PUD[3]:							

Priest Rapids Development	2052	4.8	45		28,243		747		376	9,768
Wanapum Development	2052	4.8	58		28,243		747		376	9,768
Total			956	$	203,889	$	18,605	$	7,791	$ 146,786

1. *In March 2021, PSE entered into a new PPA with Chelan County PUD for additional Rocky Reach and Rock Island output. The contract began on January 1, 2022, and continues through December 31, 2026. This agreement increases PSE's share of output by 5% for each project, which equates to an additional capacity of 31MW for Rock Island and 65MW for Rocky Reach.*
2. *In March 2021, PSE entered into a new agreement with Douglas County PUD for the extension of the Wells Project Output that began on October 1, 2021, and continues through September 30, 2024. This agreement increases PSE's share of output by 5.5% for the Wells Project, which equates to an additional capacity of 46MW.*
3. *In November 2022, PSE elected to take its portion of the Priest Rapid Meaningful Priority and was granted 4.13% share of the 2023 Priest Rapids Project output. This one-year contract begins on January 1, 2023, and continues through December 31, 2023. This agreement increases PSE's share of output by 4.13%, which equates to an additional capacity of 39MW for Priest Rapids Development and 51 MW for Wanapum Development.*

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)	2023	2024	2025	2026	2027	Thereafter	Total
Columbia River projects	$ 191,618	$ 145,078	$ 140,887	$ 138,482	$ 123,152	$ 394,875	$ 1,134,092
Electric portfolio contracts	380,559	385,807	345,257	142,273	133,903	1,776,703	3,164,502
Electric wholesale market transactions	414,278	148,628	11,616	11,616	—	—	586,138
Total	$ 986,455	$ 679,513	$ 497,760	$ 292,371	$ 257,055	$ 2,171,578	$ 4,884,732

Total purchased power contracts provided the Company with approximately 15.3 million and 13.1 million MWhs of firm energy at a cost of approximately $892.7 million and $631.4 million for the years 2022 and 2021, 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 22 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage.

The Company incurred demand charges of $138.3 million and $136.4 million for firm transportation, storage and peaking services for its natural gas customers for the years 2022 and 2021. The Company incurred demand charges of $53.9 million and $52.8 million for firm transportation, storage and peaking services for the natural gas supply for its combustion turbines for the years 2022 and 2021.

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 currently authorized rates, which are subject to change.

Natural Gas Supply and Demand Charge Obligations (Dollars in Thousands)	2023	2024	2025	2026	2027	Thereafter	Total
Natural gas wholesale market transactions	$ 1,013,547	$ 377,588	$ 351,129	$ 255,577	$ 76,453	$ —	$ 2,074,294
Firm transportation service	175,136	146,675	112,327	94,417	94,123	570,687	1,193,365
Firm storage service	9,350	7,923	7,448	7,432	7,352	1,838	41,343
Total	$ 1,198,033	$ 532,186	$ 470,904	$ 357,426	$ 177,928	$ 572,525	$ 3,309,002

Service Contracts

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

Service Contract Obligations (Dollars in Thousands)	2023	2024	2025	2026	2027	Thereafter	Total
Energy production service contracts	$33,971	$34,812	$35,772	$18,728	$19,221	$79,655	$222,159
Automated meter reading system	50,124	47,301	47,668	48,803	—	—	193,896
Total	$84,095	$82,113	$83,440	$67,531	$19,221	$79,655	$416,055

Chelan PUD Power Purchase Agreement

On February 7, 2023, PSE and Chelan PUD entered into a new power purchase agreement, under which PSE will continue to purchase 25% of the total output from the Rocky Reach and Rock Island hydroelectric projects from November 1, 2031 through October 31, 2051. Estimated payment obligations under the new power sales agreement total $3.1 billion.

Other Commitments and Contingencies

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

(16) Related Party Transactions

The Company identified no material related party transactions during the year ended December 31, 2022 and December 31, 2021.

(17) 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, 2022 and 2021, 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, 2020	$ (175,972)	$ (4,984)	$ (180,956)
Other comprehensive income (loss) before reclassifications	49,265	—	49,265
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	18,166	384	18,550
Net current-period other comprehensive income (loss)	67,431	384	67,815
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)

Details about the reclassifications out of AOCI (loss) for the years ended December 31, 2022 and 2021, 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) 2022	2021
Net unrealized gain (loss) and prior service cost on pension plans:			
Amortization of prior service cost	(a)	$ (311)	$ 1,158
Amortization of net gain (loss)	(a)	(17,693)	(24,153)
	Total before tax	$ (18,004)	$ (22,995)
	Tax (expense) or benefit	3,781	4,829
	Net of tax	$ (14,223)	$ (18,166)
Net unrealized gain (loss) on treasury interest rate swaps:			
Interest rate contracts	Interest expense	(488)	(487)
	Tax (expense) or benefit	102	103
	Net of Tax	$ (386)	$ (384)
Total reclassification for the period	Net of Tax	$ (14,609)	$ (18,550)

(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: 04/14/2023	Year/Period of Report End of: 2022/ 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		(175,986,902)			(4,968,236)		(180,955,138)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income		18,165,893			385,239		18,551,132		
3	Preceding Quarter/Year to Date Changes in Fair Value		49,265,458					49,265,458		
4	Total (lines 2 and 3)		67,431,351			385,239		67,816,590	336,064,107	403,880,697
5	Balance of Account 219 at End of Preceding Quarter/Year		(108,555,551)			(4,582,997)		(113,138,548)		
6	Balance of Account 219 at Beginning of Current Year		(108,555,551)			(4,582,997)		(113,138,548)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income		14,223,604			385,239		14,608,843		
8	Current Quarter/Year to Date Changes in Fair Value		(4,515,325)					(4,515,325)		
9	Total (lines 7 and 8)		9,708,279			385,239		10,093,518	490,950,387	501,043,905
10	Balance of Account 219 at End of Current Quarter/Year		(98,847,272)			(4,197,758)		(103,045,030)		

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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)	16,449,945,708	10,650,307,509	4,795,295,870				1,004,342,329
4	Property Under Capital Leases	293,475,429	41,575,741					251,899,688
5	Plant Purchased or Sold							
6	Completed Construction not Classified	723,383,148	342,443,905	355,745,484				25,193,759
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	17,466,804,285	11,034,327,155	5,151,041,354				1,281,435,776
9	Leased to Others							
10	Held for Future Use	46,231,981	38,857,747	7,374,234				
11	Construction Work in Progress	861,801,465	715,554,479	108,956,528				37,290,458
12	Acquisition Adjustments	282,791,675	282,791,675					
13	Total Utility Plant (8 thru 12)	18,657,629,406	12,071,531,056	5,267,372,116				1,318,726,234
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	7,461,206,807	5,074,629,251	1,916,418,469				470,159,087
15	Net Utility Plant (13 less 14)	11,196,422,599	6,996,901,805	3,350,953,647				848,567,147
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	6,854,925,784	4,810,159,731	1,904,777,615				139,988,438
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	434,822,265	93,010,762	11,640,854				330,170,649
22	Total in Service (18 thru 21)	7,289,748,049	4,903,170,493	1,916,418,469				470,159,087
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	171,296,333	171,296,333					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	7,461,206,807	5,074,629,251	1,916,418,469				470,159,087

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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: 04/14/2023	Year/Period of Report End of: 2022/ 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	79,247,190	589,271	129,754			79,706,707
4	(303) Miscellaneous Intangible Plant	117,565,443	12,928,017	9,856,677			120,636,783
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	196,926,835	13,517,288	9,986,431			200,457,692
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	136,357,191	6,058	155,016			136,208,233
10	(312) Boiler Plant Equipment	536,898,641	2,256,015	7,853,252		(8,338,080)	522,963,324
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	284,524,396	714,267	3,499,040			281,739,623
13	(315) Accessory Electric Equipment	38,592,277	1,289,058	917,344			38,963,991
14	(316) Misc. Power Plant Equipment	7,590,054		8,948			7,581,106
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)	1,050,509,552	4,265,398	12,433,600		(8,338,080)	1,034,003,270
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	168,394,463	11,375,538	502,703			179,267,298
29	(332) Reservoirs, Dams, and Waterways	368,493,490	2,848,953	5,864,818			365,477,625
30	(333) Water Wheels, Turbines, and Generators	129,845,814	9,867,191				139,713,005
31	(334) Accessory Electric Equipment	45,890,982	9,848,906	249,429			55,490,459
32	(335) Misc. Power Plant Equipment	16,561,974	123,351				16,685,325
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)	745,538,777	34,063,939	6,616,950			772,985,766

36	D. Other Production Plant						
37	(340) Land and Land Rights	16,016,762					16,016,762
38	(341) Structures and Improvements	132,078,603	1,948,592	513,274			133,513,921
39	(342) Fuel Holders, Products, and Accessories	26,274,179	440				26,274,619
40	(343) Prime Movers						
41	(344) Generators	1,630,539,239	30,715,790	22,870,478	(1,986,664)		1,636,397,887
42	(345) Accessory Electric Equipment	156,074,363	2,984,006	2,090,148			156,968,221
43	(346) Misc. Power Plant Equipment	21,449,541	108,729				21,558,270
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)	2,036,008,596	35,757,557	25,473,900	(1,986,664)		2,044,305,589
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,832,056,925	74,086,894	44,524,450	(1,986,664)	(8,338,080)	3,851,294,625
47	3. Transmission Plant						
48	(350) Land and Land Rights	63,870,804	485,135				64,355,939
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	11,878,174					11,878,174
50	(353) Station Equipment	701,220,718	11,114,610	604,407			711,730,921
51	(354) Towers and Fixtures	92,295,736	(15,850)				92,279,886
52	(355) Poles and Fixtures	432,899,468	10,484,876	2,682,472			440,701,872
53	(356) Overhead Conductors and Devices	334,133,437	3,223,549	318,371			337,038,615
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	2,511,789	(17,076)				2,494,713
57	(359.1) Asset Retirement Costs for Transmission Plant	2,580,015	654,285				3,234,300
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,679,557,731	25,929,529	3,605,250			1,701,882,010
59	4. Distribution Plant						
60	(360) Land and Land Rights	44,761,501	1,838,526			(772)	46,599,255
61	(361) Structures and Improvements	8,141,425	113,296				8,254,721
62	(362) Station Equipment	508,711,965	18,723,013	2,254,254			525,180,724
63	(363) Energy Storage Equipment – Distribution	1,210,115					1,210,115
64	(364) Poles, Towers, and Fixtures	470,309,064	41,878,755	2,440,370			509,747,449
65	(365) Overhead Conductors and Devices	595,719,303	60,049,071	5,624,346			650,144,028
66	(366) Underground Conduit	831,255,338	51,810,290	1,841,767			881,223,861
67	(367) Underground Conductors and Devices	1,157,200,306	69,004,463	5,814,237			1,220,390,532
68	(368) Line Transformers	562,395,973	36,693,019	3,508,053			595,580,939
69	(369) Services	198,810,570	5,888,428	327,702			204,371,296
70	(370) Meters	262,108,454	28,025,950	21,974,947			268,159,457
71	(371) Installations on Customer Premises	854,792					854,792
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	62,620,526	2,407,475	103,099			64,924,902
74	(374) Asset Retirement Costs for Distribution Plant	7,191,908	3,430,777				10,622,685
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,711,291,240	319,863,063	43,888,775		(772)	4,987,264,756
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	112,600,208	550,844				113,151,052
88	(391) Office Furniture and Equipment	31,107,923	5,299,800	5,220,803			31,186,920
89	(392) Transportation Equipment	6,441,438	977,456	5,236,648			2,182,246
90	(393) Stores Equipment	170,597					170,597
91	(394) Tools, Shop and Garage Equipment	21,176,970	5,129,465				26,306,435
92	(395) Laboratory Equipment	6,882,472		227,647			6,654,825
93	(396) Power Operated Equipment	4,867,994	651,581				5,519,575
94	(397) Communication Equipment	98,329,370	7,402,361	2,978,390			102,753,341
95	(398) Miscellaneous Equipment	410,840		8,280			402,560
96	SUBTOTAL (Enter Total of lines 86 thru 95)	287,088,333	20,011,507	13,671,768			293,428,072
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)	287,088,333	20,011,507	13,671,768			293,428,072
100	TOTAL (Accounts 101 and 106)	10,706,921,064	453,408,281	115,676,674	(1,986,664)	(8,338,852)	11,034,327,155
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)	10,706,921,064	453,408,281	115,676,674	(1,986,664)	(8,338,852)	11,034,327,155

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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)
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47	TOTAL					

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	DISTRIBUTION E3600 - AUTUMN GLEN SUBSTATION LAND	03/30/2009	01/31/2027	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	01/01/2026	1,041,419
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	12/31/2029	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	12/31/2030	912,413
12	DISTRIBUTION E3600 - MITIGATION LAND GOPHER	12/31/2018	02/28/2023	2,384,674
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	436,565
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	1,870,638
19	TRANSMISSION E3507 -SO. BREMERTON-BANGOR LAND	09/04/2007	01/01/2035	1,005,331
20				
21				
22				
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
47	TOTAL			38,857,747

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	ADMS-Distribution Management System	12,346,852
2	AMI Project	
3	Bainbridge Project	12,890,628
4	Baker Project	166,613,341
5	Berrydale-Krain Transmission Line Project	1,537,039
6	Bremerton-Bangor Project	1,457,762
7	Eastside Transmission Project	114,833,463
8	Fredonia Project	3,786,400
9	Greenwater Tap Project	3,168,259
10	Lakeside-Ardmore Project	
11	Other Misc. Work Orders	
12	Phantom Lake - Lake Hills Project	40,125,580
13	Residential Electric Vehicle Project	
14	Sammamish-Moorlands Project	13,292,532
15	Sedro-Bellingham Project	5,736,359
16	Skookumchuck Wind Farm Project	
17	Woodland - St Clair Project	3,261,292
18	CWIP less than $1,000,000 each - Electric Distribution	149,269,630
19	CWIP less than $1,000,000 each - Electric Transmission	146,027,867
20	CWIP less than $1,000,000 each - Electric General Plant & Intangibles	16,181,797
21	CWIP less than $1,000,000 each - Electric Generation	23,013,928
22	WSDOT	2,011,750
43	Total	715,554,479

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 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	4,517,910,593	4,517,748,168	162,425	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	354,589,151	354,589,151		
4	(403.1) Depreciation Expense for Asset Retirement Costs	8,902,654	8,902,654		
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):	(105,690)	[a](105,690)		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	363,386,115	363,386,115		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(105,690,245)	(105,690,245)		
13	Cost of Removal	(9,126,306)	(9,126,306)		
14	Salvage (Credit)	(2,325)	(2,325)		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(114,818,876)	(114,818,876)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	43,844,324	[b]43,844,324		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,810,322,156	4,810,159,731	162,425	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	921,461,342	921,461,342		
21	Nuclear Production				
22	Hydraulic Production-Conventional	251,344,527	251,344,527		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,043,961,182	1,043,961,182		
25	Transmission	633,075,387	632,912,962	162,425	
26	Distribution	1,852,824,152	1,852,824,152		
27	Regional Transmission and Market Operation				
28	General	107,655,566	107,655,566		
29	TOTAL (Enter Total of lines 20 thru 28)	4,810,322,156	4,810,159,731	162,425	

FOOTNOTE DATA

(a) Concept: OtherAccounts

The balance reported in Other as of 12/31/2021 totalling $2,723,061 represents manual adjustments associated with ARC accumulated depreciation.

(b) 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.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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	05/31/1960		10,200			10,200	
2	Retained Earnings	05/31/1960		(13,535,624)	270,654		(13,264,970)	
3	Additional Paid in Capital	05/31/1960		51,837,244			51,837,244	
4	Subtotal			38,311,820	270,654		38,582,474	
42	Total Cost of Account 123.1 $ 38,582,474.00		Total	38,311,820	270,654		38,582,474	0

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	17,117,974	21,182,653	
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)	94,918,863	110,142,293	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	4,649,945	7,620,965	Electric & Gas
8	Transmission Plant (Estimated)	631,817	709,535	Electric & Gas
9	Distribution Plant (Estimated)	9,502,621	11,260,489	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,968,321	(a)1,550,618	Electric & Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	111,671,567	131,283,900	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	(628)	(b)221,957	Electric & Gas
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	1,014,123	156,825	Electric & Gas
17				
18				
19				
20	TOTAL Materials and Supplies	129,803,036	152,845,335	

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.

(b) Concept: OtherMaterialsAndSupplies

This account is for landfill gas pipeline imbalance.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
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 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)
1	Balance-Beginning of Year	93,936	600,920	9,034		9,030		9,033		234,940		355,973	600,920
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9	Purchased: Vitol A	10,000	280,500									10,000	280,500
10	Purchased: Vitol B												
11	Transfer: Talen MT	(1,133)								5,323		4,190	
12	Initial Allocation to PSE									3,686		3,686	
13													
14													
15	Total	8,867	280,500							9,009		17,876	280,500
16													
17	Relinquished During Year:												
18	Charges to Account 509	35										35	
19	Other:												
20	Allowances Used												
20.1	California Carbon Allowances	5,424	150,353									5,424	150,353
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	97,344	731,067	9,034		9,030		9,033		243,949		368,390	731,067
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	[(a)] 4,068										4,068	
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA	420										420	

39	Cost of Sales												
40	Balance-End of Year	3,648										3,648	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)		[(b)]6										6
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AllowancesWithheldNumber

The following table reflects 2022 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	12/31/21 Estimated Balance of Withheld Allowances Years 2009-2025	Estimated EPA Withheld Allowances Sold During 2022	12/31/22 Estimated Balance of Withheld Allowances Year 2009-2025
Colstrip Unit 1	838	172	666
Colstrip Unit 2	815	171	644
Colstrip Unit 3	627	43	584
Colstrip Unit 4	1,788	34	1,754
	4,068	420	3,648

(b) Concept: AllowancesWithheldNetSalesProceedsFromAllowanceSalesAssociatedCompany

2022 proceeds from sales of allowances withheld by the Environmental Protection Agency were as follows:

Plant		2021 Proceeds
Colstrip Unit 1	$	2.58
Colstrip Unit 2		2.57
Colstrip Unit 3		0.64
Colstrip Unit 4		0.51
Total Proceeds	$	6.30

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
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												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	[a] 2012 Storm			407	2,846,812	
2	2015 Storm					
3	2016 Storm			407	6,931,618	
4	2017 Storm Excess Costs					12,707,858
5	2017 Storm Recovery			407	12,068,002	147,517
6	2018 Storm Excess Costs					12,247,269
7	2019 Storm Excess Costs					28,513,473
8	2020 Storm Excess Costs					11,400,537
9	2021 Storm Excess Costs		150,757			41,076,806
10	2022 Storm Excess Costs		21,430,716			21,430,716
20	TOTAL		21,581,473		21,846,432	127,524,176

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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).

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs 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					

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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).

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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	[(a)] See note below				
20	Total				
21	**Generation Studies**				
22	Wenatchee Solar Facilities Study	498	186053554		
23	Desert Claim 20 MW Wind Facilities Study	1,582	186055231		
24	Desert Claim 80 MW Wind Facilities Study	1,898	186055299		
25	Grays Harbor Facilities Study			(22,785)	186056890
26	Stony Lake Battery Facilities Study	3,983	186056891		
27	Leprechaun Solar System Impact Study			(55,616)	186057981
28	Energy Storage Resources Facilities Study	622	186058571		
29	South Hill Facilities Study	747	186058675		
30	BP Cherry Pt Facilities Study	5,917	186059085		
31	Logjam Battery Storage Facilities Study	293	186060050		
32	Spire Battery Storage Facilities Study	4,033	186060051		
33	Bufflehead BESS Feasibility Study	1,367	186060200		
34	Grebe BESS Feasibility Study	273	186060201		
35	Kingfisher BESS Feasibility Study	3,554	186060202		
36	Vireo BESS Feasibility Study	347	186060203		
37	Sedro BESS Feasibility Study	508	186060333		
38	Green Water BESS Facilities Study	137	186060928		
39	South Bremerton Feasibility Study	297	186061060		
40	AE Solar Feasibility Study	1,055	186061274		
41	Nirvana BESS Feasibility Study	1,576	186061322		
42	Kodiak Simple Cycle Feasibility Study	4,219	186061323		
43	Seabrooke Simple Cycle Feasibility Study	533	186061391		
44	Bufflehead BESS Facilities Study	17,429	186061442		
45	Olphant Wind Feasibility Study	422	186061556		
46	Sedro BESS System Impact Study	137	186061577		
47	Seabrooke Simple Cycle System Impact Study	10,987	186061913		
48	Agate BESS Feasibility Study	8,217	186061914		
49	Starwood BESS System Impact Study	1,105	186062158		
50	Grebe BESS Facilities Study	10,673	186062159		
51	Wilson Creek 1 Feasibility Study			(10,713)	186062160
52	Wilson Creek 2 Feasibility Study			(4,989)	186062161
53	Sedro BESS Facilities Study	11,827	186062169		
54	Goldeneye BESS Facilities Study	18,339	186062247		
55	Spire II Energy Storage System Impact Study	8,197	186062279		
56	Lower Snake River System Impact Study	792	186062280		
57	Clearway LSR Feasibility Study			(5,077)	186062381
58	Appaloosa II Solar System Impact Study	1,090	186062438		
59	Viero BESS Facilities Study	27,229	186062471		
60	AE Solar System Impact Study	1,684	186062472		

61	Kodiak Simple Cycle System Impact Study	3,616	186062473			
62	Double R BESS Feasibility Study	3,115	186062510			
63	South Bremerton System Impact Study	3,811	186062536			
64	Kingfisher BESS Facilities Study	23,199	186062553			
65	Centralia BESS System Impact Study	693	186062604			
66	Sinclair BESS Facilities Study	32	186062677			
67	AE Solar Permissible Tech Study	396	186062899			
68	Starwood FESS Facilities Study	3,176	186062926			
69	Clover Creek BESS Facilities Study	1,377	186063201			
70	Appaloosa I Solar Facilities Study	2,945	186063202			
71	Seabrooke Simple Cycle Facilities Study	10,647	186063298			
39	Total	204,574			(99,180)	
40	Grand Total	204,574			(99,180)	

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	[(a)] Unamortized Energy Conservation Costs	3,573,098	304,544,366	182, 908	297,821,575	10,295,889
2	[(b)] WUTC Deferred AFUDC	62,244,484	2,218,899	406	3,000,294	61,463,089
3	[(c)] Colstrip 1&2 Western Energy Coal Reserve - 10 years	126,136,893	12,247,031	186, 406	9,628,880	128,755,044
4	[(d)] Colstrip Deferred Depreciation - 17.5 years	344,821		406	138,804	206,017
5	[(e)] Environmental Remediation Costs	20,760,361	3,598,314	228, 407, 822	9,489,796	14,868,879
6	[(f)] Property Tax Tracker	25,895,676	36,410,721	408	49,908,516	12,397,881
7	[(g)] Decoupling Mechanism	82,104,365	98,262,081	Multiple	143,593,374	36,773,072
8	[(h)] Low Income Home Energy Assistance Program	820	54,307,223	Multiple	36,937,561	17,370,482
9	[(i)] Power Cost Adjustment Mechanism	79,546,584	296,069,852	419, 557	263,409,314	112,207,122
10	[(j)] White River Regulatory Assets - 3 years	3,780				3,780
11	[(k)] Chelan PUD - 20 years	69,699,311		555	7,088,065	62,611,246
12	[(l)] Mint Farm Deferral - 15 years	9,210,179		407	2,885,052	6,325,127
13	[(m)] Lower Snake River Deferral - 25 years	57,999,724		253, 407	5,498,523	52,501,201
14	[(n)] WUTC AMI, EV & GTZ Deferral	55,900,892	19,773,583	182, 407	35,921,143	39,753,332
15	[(o)] PLR EDIT	18,850,453	14,205,060	456, 495	34,128,893	(1,073,380)
16	[(p)] SPI Biomass	1,211,768		407	612,720	599,048
17	LNG Exp Deferral		9,981,418			9,981,418
44	TOTAL	613,483,209	851,618,548		900,062,510	565,039,247

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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 and UG-130138.

(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 and UE-180877. Amortization effective March 2019.

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Included in Washington Commission Dockets UE-190530 and UE-190529 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.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	1,682,850	134,195	186,253	356,613	1,460,432
2	Tacoma LNG	(108,727,349)	30,826,219	182, 419	12,390,163	(90,291,293)
3	Damage Claims	4,749,763	14,346,304	186	13,862,712	5,233,355
4	Clearing Account Charges	362,274	3,181,286	184,186	1,258,495	2,285,065
5	FAS133 Net Unrealized					
6	Chelan Prepayments - 20 Yrs	5,068,694	465,554	555	562,805	4,971,443
7	Ferndale Maintenance - 12 Yrs	1,322,720	5,076,699	553	240,495	6,158,924
8	Encogen Maintenance - 10 Yrs	5,181,586		553	1,172,145	4,009,441
9	Environmental Remediation Exp	107,217,129	25,203,387	186, 228, 822	5,396,361	127,024,155
10	Real Estate Operating Leases - 7 Yrs	8,442,441	11,813	253, 931	117,344	8,336,910
11	FSAS 71 - Snoqualmie License	7,446,472		253	1,692	7,444,780
12	Baker Article	6,173,916	850,474	242	350,658	6,673,732
13	SFAS 71 - Baker License	54,524,623	867,098	253	342,102	55,049,619
14	Colstrip Maintenance - 4 Yrs	6,478,468	2,047	513	662,590	5,817,925
15	AMI	19,730,437	17,394,598	253	1,592,775	35,532,260
16	Fredonia Maintenance - 9-11 Yrs	5,093,850		553	1,073,705	4,020,145
17	Fredrickson Maintenance - 7 Yrs	1,824,778		513,553	862,293	962,485
18	Goldendale Maintenance - 4-8 Yrs	4,170,031	3,599,484	514, 553, 822	1,855,781	5,913,734
19	Whitehorn Maintenance - 6-12 Yrs	829,027		186,553	213,912	615,115
20	Mint Farm Maintenance - 3-7 Yrs	4,805,266	3,818,040	553, 186, 822	1,744,234	6,879,072
21	Sumas Maintenance - 11 Yrs	2,200,359		553	322,720	1,877,639
22	Non-Temp Facility	19,139,313	19,705,634	186	19,771,466	19,073,481
23	Residential Exchange	10,782,445	145,984,279	253	140,981,615	15,785,109
24	GTZ Depreciation	11,443,973	11,081,022	407, 419	23,956	22,501,039
25	Minor Items	11,259,822	58,444,451	Various	57,327,429	12,376,844
26	COVID-19 Items	25,410,484	38,754,994	Various	57,114,721	7,050,757
27	Regulatory Fees		11,646,555	407	4,087,689	7,558,866
47	Miscellaneous Work in Progress					
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)					
49	TOTAL	216,613,372				284,321,034

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	104,622,173	96,005,049
3	Pension and Other Compensation	35,866,381	33,166,144
4	Regulatory Assets	58,194,954	63,694,514
5	Lease		64,531,287
7	Other	42,007,648	35,239,080
8	TOTAL Electric (Enter Total of lines 2 thru 7)	240,691,156	292,636,074
9	Gas		
10	SFAS 109	57,632,533	50,702,899
11	Derivative Instruments	16,711,495	72,229,021
15	Other	2,284,912	3,827,367
16	TOTAL Gas (Enter Total of lines 10 thru 15)	76,628,940	126,759,287
17.1	Other (Non-Operating)	1,947,675	10,621,084
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	319,267,771	430,016,445

Notes

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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: 2023-04-14	Year/Period of Report End of: 2022/ 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.

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
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.
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.
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	3,014,096,691
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	50,000,000
16	Ending Balance Amount	3,064,096,691
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	3,064,096,691

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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: 04/14/2023	Year/Period of Report End of: 2022/ 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)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
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	300,000,000	[(a)] 21,060,000
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	100,000,000	7,000,000
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	250,000,000	13,707,500
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	250,000,000	16,810,000
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	300,000,000	18,822,000
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	350,000,000	20,149,500
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	325,000,000	18,833,750
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	250,000,000	14,410,000
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	250,000,000	11,085,000
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	45,000,000	2,115,000
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	300,000,000	16,914,000
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	425,000,000	18,275,000
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	600,000,000	25,338,000
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	450,000,000	14,625,000
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	138,460,000	5,399,940
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	23,400,000	936,000
20	2.893% Senior Notes Due 09/51		450,000,000					09/15/2021	09/15/2051	09/15/2021	09/15/2051	450,000,000	13,018,500
21	Bonds assumed which were originally issued by Washington Natural Gas Company												
22	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	15,000,000	1,072,500

23	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	2,000,000	144,000
24	Subtotal		4,823,860,000			43,352,453						4,823,860,000	239,715,690
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													
39	Subtotal												
33	TOTAL		4,823,860,000									4,823,860,000	239,715,690

FOOTNOTE DATA

(a) 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: 04/14/2023	Year/Period of Report End of: 2022/ 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)	490,950,387
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	80,223,051
11	Others	[a]212,057,350
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](395,015,813)
27	Federal Tax Net Income	388,214,975
28	Show Computation of Tax:	
29	Taxable Income	388,214,975
30	Tax @21%	81,525,145
31	PTC	
32	Current Federal Tax	81,525,145
33	Current State Tax	869,191
34	Deferred Tax	(2,171,285)
35	Total Tax	80,223,051

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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: 04/14/2023	Year/Period of Report End of: 2022/ 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 Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	Municipal	Local Tax	WA	2021	20,207,471		148,010,315	145,326,481		22,891,305		93,960,045			54,050,270
2	**Subtotal Local Tax**				20,207,471		148,010,315	145,326,481		22,891,305		93,960,045			54,050,270
3	Other	Other Taxes	WA	2021	908,269	(285)	2,926,654	2,702,206		1,133,002		3,161,911			(235,257)
4	**Subtotal Other Tax**				908,269	(285)	2,926,654	2,702,206		1,133,002		3,161,911			(235,257)
5	Property	Ad Valorem Tax	WA, OR, MT	2021	74,192,205	273,169	68,716,215	78,015,477		64,619,774		53,342,664			15,373,551
6	**Subtotal Property Tax**				74,192,205	273,169	68,716,215	78,015,477		64,619,774		53,342,664			15,373,551
7	Income	Income Tax	Fed, CA, MT, OR	2021	10,914,743	7,735	81,954,336	93,657,801		(796,457)		42,353,803			40,040,532
8	**Subtotal Income Tax**				10,914,743	7,735	81,954,336	93,657,801		(796,457)		42,353,803			40,040,532
9	Excise	Excise Tax	WA	2021	27,180,959	(176,335)	148,827,535	147,563,817		28,621,012		98,302,093			50,085,443
10	**Subtotal Excise Tax**				27,180,959	(176,335)	148,827,535	147,563,817		28,621,012		98,302,093			50,085,443
11	Payroll	Payroll Tax	Fed, WA, OR, TX, MI	2021	4,175		28,022,845	28,022,674		4,346		10,593,972			17,428,873
12	**Subtotal Payroll Tax**				4,175		28,022,845	28,022,674		4,346		10,593,972			17,428,873
40	TOTAL				133,407,822	104,284	478,457,900	495,288,456		116,472,982		301,714,488			176,743,412

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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: 04/14/2023	Year/Period of Report End of: 2022/ 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	8,417,775	Various	4,020,589	2,901,847	7,299,033
2	SFAS 106 Unfunded Liability	13,251,015	Various	12,549,795	20,267,117	20,968,337
3	Low Income Program	15,326,887	Various	42,479,985	52,970,508	25,817,410
4	Sch 85 Line Extension Cost	16,171,051	456	591,428	1,584,535	17,164,158
5	Green Power Tariff	6,731,072	456	1,471,952	3,343,819	8,602,939
6	Landlord Incentives - 5-11 Yrs	12,326,778	931	4,859,048	5,734,161	13,201,891
7	Workers Comp - IBNR	1,997,243	186	334,357	111,939	1,774,825
8	Residential Exchange		555	274,314,683	274,314,683	
9	Decoupling	2,979,105	456	2,979,105		
10	LSR License O&M - 25 Yrs	8,158,187	Various	8,913,248	8,418,016	7,662,955
11	Snoqualmie License O&M	7,446,472	186	1,692		7,444,780
12	Baker License Misc Def	54,524,623	186	342,102	867,098	55,049,619
13	Unearned Revenue - 11-20 Yrs	3,966,809	253, 454	7,541,733	4,889,688	1,314,764
14	Deferred Pole Contact		822	57,951	57,951	
15	PGA Unrealized Gain	60,728,494	175, 244	1,702,689,326	1,929,685,841	287,725,009
16	Equity Reserve AMI	7,669,442	419, 186	1,592,776	3,820,604	9,897,270
17	Montana PTC	45,328,445	108	45,328,445		
18	Unclaimed Property	126,442	131	934,978	1,260,041	451,505
19	Colstrip 3&4 Final	246,143	131	1,814,589	1,678,883	110,437
20	Mint Farm Misc Def Credit - 15 Yrs	2,892,541	419	884,723		2,007,818
21	Deferred Interchange		555	6,257,731	6,257,731	
22	Tacoma LNG	14,232,893	419		8,187,912	22,420,805
23	Minor Items	691,891	Various	1,164,745	984,306	511,452
24	Covid-19 Help	14,924,390	Various	11,061,183	1,148,579	5,011,786
25	Microsoft EA		232, 143		1,752,928	1,752,928
26	LT Payable - Franchise	14,450,730	Various			14,450,730
27	Bid and Success Fees	535,369	923	535,369		
28	AMI Topside		253		7,706,610	7,706,610
47	TOTAL	313,123,797		2,132,721,533	2,337,944,797	518,347,061

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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										

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	804,626,637	1,149,455	36,186,566					various	21,374,587	790,964,113
3	Gas	385,888,909	2,383,308	5,290,925					various	5,771,196	388,752,488
4	Other (Specify)	(602,774)	(2,085,120)								(2,687,894)
5	Total (Total of lines 2 thru 4)	1,189,912,772	1,447,643	41,477,491						27,145,783	1,177,028,707
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,189,912,772	1,447,643	41,477,491						27,145,783	1,177,028,707
10	Classification of TOTAL										
11	Federal Income Tax	1,189,912,772	1,447,643	41,477,491						27,145,783	1,177,028,707
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: 04/14/2023	Year/Period of Report End of: 2022/ 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.

			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 283										
2	Electric										
3	Pension related	46,016,126	2,378,799	1,267,700							47,127,225
4	Storm Damage	26,835,718	4,721,267	4,776,909							26,780,076
5	Regulatory Assets	73,966,599	91,859,845	93,702,859							72,123,585
6	Lease	(51,176)	(437,188)	(65,116,069)							64,627,705
7	Other	3,594,188	1,691,600	427,430							4,858,358
9	TOTAL Electric (Total of lines 3 thru 8)	150,361,455	100,214,323	35,058,829							215,516,949
10	Gas										
11	Derivative Instruments	16,711,495	114,031,764	58,514,238							72,229,021
12	Pension related	5,740,460	1,226,534	653,640							6,313,354
13	Regulatory Assets	11,885,523	9,063,085	11,977,187							8,971,421
14	Other	553,015	6,079,402								6,632,417
17	TOTAL Gas (Total of lines 11 thru 16)	34,890,493	130,400,785	71,145,065							94,146,213
18	TOTAL Other	[(a)]30,359,296	117,490,840	62,791,309			Various	149,244			84,909,583
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	215,611,244	348,105,948	168,995,203				149,244			394,572,745
20	Classification of TOTAL										
21	Federal Income Tax										
22	State Income Tax										
23	Local Income Tax										

NOTES

Local Income Tax

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Electric and gas derivative instruments reported within operating electric and gas in 2021 were moved to non-operating for 2022 reporting, as electric and gas derivatives are non-operating in nature.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	[(a)] Renewable Energy Credits	369,248	Multiple	1,558,931	1,072,193	(117,490)
2	[(b)] Treasury Grants-Wind Project Expansion	(114,752)	254, 407.4	1,763,061	1,704,837	(172,976)
3	[(c)] PTC Cost Deferral	1	108	1		
4	[(d)] Decoupling Mechanisms	36,506,000	Multiple	95,309,014	122,008,588	63,205,574
5	[(e)] Regulatory Liability Tax Reform	838,172,924	190	42,177,654	4,729,818	800,725,088
6	[(f)] Green Direct Liquidated Damages	13,193,615	456	1,357,066		11,836,549
7	[(g)] Gain on Sale Shuffleton-Electric	(26,753)				(26,753)
8	[(h)] FAS 109 EDIT Unprotected Gas & Electric	28,367,379	190, 283	17,369,123		10,998,256
9	[(i)] Lund Hill Liquidated Damages				828,503	828,503
10	[(j)] NWP Refund for Electric				4,353,000	4,353,000
41	TOTAL	916,467,662		159,534,850	134,696,939	891,629,751

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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-070725, UE-101581, UE-170033, and UG-170034. The REC liability balance isused to offset PTC receivables.

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(e) 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.

(f) 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.

(g) 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).

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

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

(j) 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.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	1,381,833,366	1,318,319,153	11,753,057	11,479,046	1,065,508	1,053,027
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	[(a)]988,817,103	[(e)]909,277,341	[(i)]8,677,178	8,402,057	133,609	132,664
5	Large (or Ind.) (See Instr. 4)	[(b)]119,862,308	[(f)]111,254,647	[(j)]1,113,909	1,082,718	3,238	3,282
6	(444) Public Street and Highway Lighting	18,414,824	17,717,234	69,271	72,794	8,039	7,878
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	2,508,927,601	2,356,568,375	21,613,415	21,036,615	1,210,394	1,196,851
11	(447) Sales for Resale	546,960,679	293,007,158	6,044,433	6,649,948	8	8
12	TOTAL Sales of Electricity	3,055,888,280	2,649,575,533	27,657,848	27,686,563	1,210,402	1,196,859
13	(Less) (449.1) Provision for Rate Refunds		(766,934)				
14	TOTAL Revenues Before Prov. for Refunds	3,055,888,280	2,650,342,467	27,657,848	27,686,563	1,210,402	1,196,859
15	Other Operating Revenues						
16	(450) Forfeited Discounts	(1,092)	(2,300)				
17	(451) Miscellaneous Service Revenues	[(c)]14,470,160	[(g)]15,612,318				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	19,386,738	18,912,459				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[(d)]52,511,725	[(h)]44,904,423				
22	(456.1) Revenues from Transmission of Electricity of Others	36,229,675	34,416,813				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	122,597,206	113,843,713				
27	TOTAL Electric Operating Revenues	3,178,485,486	2,764,186,180				

Line12, column (b) includes $ 7,357,008 of unbilled revenues.
Line12, column (d) includes 56,203 MWH relating to unbilled revenues

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $7,646,663 of electric transportation revenues classified on page 300 as (456.1), Revenues from Transmission of Electricity of Others.

(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Includes $3,150,415 for electric transportation revenues classified on page 300 as (456.1), Revenues from Transmission of Electricity of Others.

(c) 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

(d) Concept: OtherElectricRevenue

Amounts Greater than $250,000 - (456) Other Revenues		
Decoupling Revenue	$	(49,490,067)
Gain/(Loss) on Non-Core Gas		111,024,352
Electric Over Earnings		—
Green Energy Option Profit/Loss Deferral		(1,748,334)
Green Direct Liquidated Damages Amortization		1,357,067
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

(e) Concept: SmallOrCommercialSalesElectricOperatingRevenue

This includes $6,348,973 of transportation revenue

(f) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

This includes $2,987,357 of transportation revenue

(g) Concept: MiscellaneousServiceRevenues

Amounts Greater than $250,000 - (451) - Misc. Services Revenues		
Schedule 87 Tax Surcharge	$	8,069,150
Temporary Service Charge		1,360,029
Line Extension Revenue		1,813,409
Disconnection/Reconnection Charges		1,317,167
Non-Consumption & Consumption Misc. Service Charges		1,873,074
Schedule 73 Conversion		466,514
Wireless Application Fee Revenue		302,350

(h) Concept: OtherElectricRevenue

Amounts Greater than $250,000 - (456) Other Revenues		
Decoupling Revenues	$	(29,957,344)
Gain/(Loss) on sales or assignment of Non-core Gas		48,961,486
Green Direct Liquidated Damages Amortization		1,119,664
REC Revenue		838,486
AMI Return Deferral		7,170,320
Excess Deferred Income Tax Private Letter Ruling Regulatory Asset Recognition		15,702,432
Other Elec Revenue		977,919

(i) Concept: MegawattHoursSoldSmallOrCommercial

Excludes 325,493 MWh of electric transportation volumes.

(j) Concept: MegawattHoursSoldLargeOrIndustrial

Excludes 1,975,218 MWh of electric transportation volumes.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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)
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46	TOTAL				

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	11,720,953	1,378,382,948	1,065,506	11,000	0.1176
2	SCH_7AE	2,746	284,530	2	1,372,800	0.1036
41	TOTAL Billed Residential Sales	11,723,699	1,378,667,478	1,065,508	1,383,800	0.1176
42	TOTAL Unbilled Rev. (See Instr. 6)	29,358	3,165,888			0.1078
43	TOTAL	11,753,057	1,381,833,366	1,065,508	1,383,800	0.1176

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	268,529	32,950,185	31,086	8,638	0.1227
2	SCH_10E	21,915	2,137,160	12	1,826,221	0.0975
3	SCH_11E	134,300	14,072,630	310	433,225	0.1048
4	SCH_12E	16,382	1,633,547	12	1,365,184	0.0997
5	SCH_24EC	2,445,538	297,881,756	90,846	26,920	0.1218
6	SCH_25EC	2,716,395	313,393,933	7,298	372,211	0.1154
7	SCH_26EC	1,594,967	172,146,842	741	2,152,453	0.1079
8	SCH_29E	14,287	1,368,668	623	22,932	0.0958
9	SCH_31EC	846,610	89,193,261	367	2,306,840	0.1054
10	SCH_35E	4,259	297,950	2	2,129,518	0.0700
11	SCH_43E	130,194	13,800,267	144	904,123	0.1060
12	SCH_46EC	19,573	1,574,077	2	9,786,397	0.0804
13	SCH_49EC	432,792	35,104,445	14	30,913,716	0.0811
14	SCH_55E	1,993	624,979	838	2,379	0.3135
15	SCH_56E	1,700	633,584	886	1,918	0.3728
16	SCH_58E	2,028	452,514	307	6,606	0.2231
17	SCH_59E	79	21,175	35	2,263	0.2674
18	SCH_449EC		56,427	1		
19	SCH_MSOFT		7,468,482	85		
41	TOTAL Billed Small or Commercial	8,651,541	984,811,882	133,609	52,261,544	0.1138
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	25,637	4,005,221			0.1562
43	TOTAL Small or Commercial	[(a)]8,677,178	[(b)]988,817,103	133,609	52,261,544	0.1140

FOOTNOTE DATA

(a) Concept: MegawattHoursSoldSmallOrCommercial

Excludes 325,493 MWh of electric transportation volumes.

(b) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $7,646,663 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: 04/14/2023	Year/Period of Report End of: 2022/ 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.
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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_24EI	81,781	10,127,576	2,594	31,564	0.1238
2	SCH_25EI	147,392	17,860,871	423	348,444	0.1212
3	SCH_26EI	188,872	20,917,031	83	2,275,562	0.1107
4	SCH_31EI	514,853	53,559,284	118	4,363,163	0.1040
5	SCH_46EI	75,732	5,671,678	4	18,933,062	0.0749
6	SCH_49EI	102,881	7,973,831	3	34,293,566	0.0775
7	SCH_449EI		2,694,534	10		
8	SCH_459EI		539,737	3		
41	TOTAL Billed Large (or Ind.) Sales	1,111,511	119,344,542	3,238	60,245,361	0.1074
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	2,398	517,766			0.2159
43	TOTAL Large (or Ind.)	[a]1,113,909	[b]119,862,308	3,238	60,245,361	0.1076

FOOTNOTE DATA

(a) Concept: MegawattHoursSoldLargeOrIndustrial

Excludes 1,975,218 MWh of electric transportation volumes.

(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Includes $3,150,415 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: 04/14/2023	Year/Period of Report End of: 2022/ 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)
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41	TOTAL Billed Commercial and Industrial Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)					

43	TOTAL					

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	600	1	7,080	0.0847
2	SCH_24EL	9,655	1,285,120	1,108	8,714	0.1331
3	SCH_25EL	1,045	156,823	8	130,570	0.1501
4	SCH_50E	51	5,809	10	5,115	0.1136
5	SCH_51E	3,100	1,120,978	1,313	2,361	0.3616
6	SCH_51S	1	313	2	464	0.3369
7	SCH_52E	12,519	2,010,975	2,260	5,539	0.1606
8	SCH_53E	36,390	13,051,267	3,210	11,321	0.3586
9	SCH_53S	6	2,144	3	2,117	0.3376
10	SCH_54E	5,509	581,341	50	110,176	0.1055
11	SCH_57E	2,201	409,930	74	29,747	0.1862
41	TOTAL Billed Public Street and Highway Lighting	70,484	18,625,300	8,039	313,204	0.2642
42	TOTAL Unbilled Rev. (See Instr. 6)	(1,213)	(210,476)			0.1735
43	TOTAL	69,271	18,414,824	8,039	313,204	0.2658

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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)
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41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					

43	TOTAL					

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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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)
41	TOTAL Billed - All Accounts	21,557,235	2,501,449,202	1,210,394	114,203,909	
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	56,180	7,478,399			
43	TOTAL - All Accounts	21,613,415	2,508,927,601	1,210,394	17,857	0.1120

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	0.130	0.130	0.130	784	8,160	27,546	[(a)]2,688	38,394
2	Port of Brownsville	RQ	Sch005	0.207	0.207	0.207	1,448	13,999	50,896	[(b)]2,733	67,628
3	City of Des Moines	RQ	Sch005	0.226	0.226	0.226	1,362	14,208	47,861	[(c)]2,603	64,672
4	Kingston Port District	RQ	Sch005	0.127	0.127	0.127	713	8,031	25,066	[(d)]1,345	34,442
5	Kittitas Co PUD	RQ	Sch005	0.037	0.037	0.037	185	2,742	6,498		9,240
6	City of Oak Harbor	RQ	Sch005	0.111	0.111	0.111	619	6,967	21,750	[(e)]2,368	31,085
7	Poulsbo Port District	RQ	Sch005	0.083	0.083	0.083	508	5,243	17,850	[(f)]1,389	24,482
8	Port of Skagit - LaConner Marina	RQ	Sch005	0.083	0.083	0.083	522	5,229	18,343	[(g)]965	24,537
9	Port of Skagit - North Basin	RQ	Sch005	0.157	0.157	0.157	972	9,916	34,146	[(h)]4,738	48,800
10	Change in Unbilled Revenue	RQ	Sch005				23	(410)	807		397
11	Avangrid Renewables, LLC	AD	FERC #8				(400)			[(i)](13,676)	(13,676)
12	Avangrid Renewables, LLC	OS	FERC #8				626,024		55,799,048		55,799,048
13	Avangrid Renewables, LLC	OS	FERC #9				86		10,096		10,096
14	Avista Corp. WWP Division	AD	FERC #8				45			[(j)]14,225	14,225
15	Avista Corp. WWP Division	OS	FERC #8				37,005		3,677,100		3,677,100
16	Avista Corp. WWP Division	OS	FERC #9				41		5,317		5,317
17	BC Hydro	OS	FERC #9				100		6,622		6,622
18	Bonneville Power Administration	AD	FERC #8				(61)			[(k)](25,490)	(25,490)
19	Bonneville Power Administration	OS	FERC #8				433,890		33,834,589		33,834,589
20	Bonneville Power Administration	OS	FERC #9				76		4,016		4,016
21	BP Energy Company	AD	FERC #8				16			[(l)]2,116	2,116
22	BP Energy Company	OS	FERC #8				302,331		34,923,808		34,923,808
23	Brookfield Renewable Trading and Marketing LP	OS	FERC #8				14,335		1,190,254		1,190,254
24	California ISO	OS	FERC #8				704,157		52,231,747		52,231,747
25	Chelan County PUD	OS	FERC #8				810		54,010		54,010
26	Chelan County PUD	OS	FERC #9				10		493		493

27	Citigroup Energy Inc.	AD	FERC #8							[m]1	1
28	Citigroup Energy Inc.	OS	FERC #8				242,101		32,558,984		32,558,984
29	City of Roseville	OS	FERC #8				11,834		447,921		447,921
30	Clatskanie Peoples Utility District	AD	FERC #8				14			[n]2,275	2,275
31	Clatskanie Peoples Utility District	OS	FERC #8				7,555		479,714		479,714
32	ConocoPhillips Company	AD	FERC #8				(163)			[o](13,392)	(13,392)
33	ConocoPhillips Company	OS	FERC #8				647,105		48,870,055		48,870,055
34	Constellation Energy Generation, LLC	AD	FERC #8				(23)			[p](46,922)	(46,922)
35	Constellation Energy Generation, LLC	OS	FERC #8				22,814		1,553,906		1,553,906
36	Dynasty Power Inc.	OS	FERC #8				7,516		1,173,422		1,173,422
37	EDF Trading N.A., LLC	OS	FERC #8				22,223		4,777,947		4,777,947
38	Energy Keepers, Inc.	AD	FERC #8				12			[q]1,800	1,800
39	Energy Keepers, Inc.	OS	FERC #8				4,160		321,492		321,492
40	Eugene Water & Electric Board	AD	FERC #8				46			[r]6,275	6,275
41	Eugene Water & Electric Board	OS	FERC #8				33,532		2,544,689		2,544,689
42	Grant County PUD No.2	OS	FERC #9				4		307		307
43	Gridforce Energy Management, LLC.	AD	FERC #8							[s]1,944	1,944
44	Gridforce Energy Management, LLC.	OS	FERC #9				626		39,271		39,271
45	Idaho Power Company	AD	FERC #8				576			[t]339,855	339,855
46	Idaho Power Company	OS	FERC #8				77,189		10,817,642		10,817,642
47	Idaho Power Company	OS	FERC #9				75		9,924		9,924
48	Mercuria Energy America, LLC	AD	FERC #8				45			[u]1,068	1,068
49	Mercuria Energy America, LLC	OS	FERC #8				346,632		38,179,304		38,179,304
50	Morgan Stanley Capital Group Inc.	AD	FERC #8				34			[v]6,104	6,104
51	Morgan Stanley Capital Group Inc.	OS	FERC #8				283,970		38,488,973		38,488,973
52	NaturEner Power Watch, LLC	AD	FERC #8							[w]481	481
53	NaturEner Power Watch, LLC	OS	FERC #9				52		1,659		1,659
54	NextEra Energy Marketing, LLC	OS	FERC #8				597		12,537		12,537
55	NorthWestern Energy	OS	FERC #8				29,915		2,077,194		2,077,194
56	NorthWestern Energy	OS	FERC #9				41		3,657		3,657
57	PacifiCorp	AD	FERC #8							[x]105	105
58	PacifiCorp	OS	FERC #8				150,188		14,792,797		14,792,797
59	PacifiCorp	OS	FERC #9				92		6,656		6,656
60	Portland General Electric Company	AD	FERC #8							[y](200)	(200)
61	Portland General Electric Company	OS	FERC #8				334,503		26,400,729		26,400,729
62	Portland General Electric Company	OS	FERC #9				39		2,013		2,013
63	Powerex Corp.	OS	FERC #8				199,218		9,720,557		9,720,557
64	Public Service Company of Colorado	OS	FERC #8				200		4,400		4,400
65	Rainbow Energy Marketing	OS	FERC #8				8,315		313,404		313,404
66	Sacramento Municipal Utility District	AD	FERC #8							[z]100	100
67	Sacramento Municipal Utility District	OS	FERC #8				29,524		852,518		852,518
68	Sacramento Municipal Utility District	OS	FERC #9				23		1,252		1,252
69	Seattle City Light Marketing	AD	FERC #8							[aa]148	148
70	Seattle City Light Marketing	OS	FERC #8				86,365		10,560,206		10,560,206
71	Shell Energy North America (US)	OS	FERC #8				263,034		22,675,558		22,675,558
72	Snohomish County PUD	AD	FERC #8				12			[ab]2,280	2,280
73	Snohomish County PUD	OS	FERC #8				33,043		3,426,565		3,426,565

74	Tacoma Power	OS	FERC #8				22,227		1,619,779		1,619,779
75	The Energy Authority	AD	FERC #8				(18)			[ac] (2,286)	(2,286)
76	The Energy Authority	OS	FERC #8				149,976		12,924,763		12,924,763
77	TransAlta Energy Marketing U.S.	AD	FERC #8				(1)			[ad] (21,973)	(21,973)
78	TransAlta Energy Marketing U.S.	OS	FERC #8				827,101		74,637,853		74,637,853
79	TransCanada Energy Sales Ltd.	OS	FERC #8				55,475		3,186,566		3,186,566
80	Turlock Irrigation District	AD	FERC #8							[ae] 338	338
81	Turlock Irrigation District	OS	FERC #8				585		26,645		26,645
82	Vitol Inc.	OS	FERC #8				12,449		859,167		859,167
83	Western Area Power Admin (SN)	OS	FERC #8				8,000		254,700		254,700
15	Subtotal - RQ						7,136	74,085	250,763	18,829	343,677
16	Subtotal-Non-RQ						6,037,297		546,361,826	255,176	546,617,002
17	Total						6,044,433	74,085	546,612,589	274,005	546,960,679

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: OtherChargesRevenueSalesForResale

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

(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

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	(400)	—	—	(400)
Amount	($13,176)	($500)	$—	($13,676)

(j) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	—	45	—	45
Amount	$—	$14,225	$—	$14,225

(k) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	—	(61)	—	(61)
Amount	($120)	($25,371)	$1	($25,490)

*Accounting adjustments not in EQR refiling. Deemed immaterial.

(l) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	16	—	—	16
Amount	$2,616	($500)	$—	$2,116

(m) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	—	—	—	—
Amount	$—	$—	$1	$1

*Accounting adjustments not in EQR refiling. Deemed immaterial.

(n) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	5	9	—	14
Amount	$250	$2,025	$—	$2,275

(o) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	(6)	(157)	—	(163)
Amount	$8,879	($11,996)	($10,275)	($13,392)

*Correction of September 2022 transaction made after EQR refiling. Deemed immaterial, so no second refiling was made.

(p) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	124	(147)	—	(23)
Amount	$5,138	($52,060)	$—	($46,922)

(q) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	12	—	—	12
Amount	$1,800	$—	$—	$1,800

(r) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	(5)	51	—	46
Amount	($250)	$6,525	$—	$6,275

(s) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	—	—	—	—
Amount	$1,944	$—	$—	$1,944

(t) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	(514)	1,090	—	576
Amount	$7,990	$331,864	$—	$339,854

(u) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	—	—	45	45
Amount	$—	$—	$1,068	$1,068

*Accounting adjustment for misclassification of transactions between purchases and sales. Deemed immaterial.

(v) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	—	34	—	34
Amount	$—	$6,104	$—	$6,104

(w) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	—	—	—	—
Amount	$481	$—	$—	$481

(x) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	—	—	—	—
Amount	$105	$—	$—	$105

(y) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	—	—	—	—
Amount	($200)	$—	$—	($200)

(z) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	—	—	—	—
Amount	$100	$—	$—	$100

(aa) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	—	—	—	—
Amount	$148	$—	$—	$148

(ab) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	—	12	—	12
Amount	$—	$2,280	$—	$2,280

(ac) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	(18)	—	—	(18)
Amount	($2,286)	$—	$—	($2,286)

(ad) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	84	(85)	—	(1)
Amount	($2,894)	($19,179)	$100	($21,973)

*Accounting adjustments not in EQR refiling. Deemed immaterial.

(ae) Concept: OtherChargesRevenueSalesForResale

	Prior Period (2021) Adjustments	Post Period (2023) Adjustments	EQR Corrections *	Total
MWH	—	—	—	—
Amount	$338	$—	$—	$338

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	1,386,767	1,256,390
5	(501) Fuel	57,889,027	49,596,334
6	(502) Steam Expenses	6,461,530	8,045,498
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,850,235	1,587,315
10	(506) Miscellaneous Steam Power Expenses	9,838,218	8,983,002
11	(507) Rents		(67)
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	77,425,777	69,468,472
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,027,119	998,546
16	(511) Maintenance of Structures	1,572,491	1,483,644
17	(512) Maintenance of Boiler Plant	10,200,516	9,593,449
18	(513) Maintenance of Electric Plant	3,777,527	5,110,349
19	(514) Maintenance of Miscellaneous Steam Plant	1,652,630	1,839,520
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	18,230,283	19,025,508
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	95,656,060	88,493,980
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	1,838,698	1,687,049
45	(536) Water for Power		

46	(537) Hydraulic Expenses	3,493,327	3,184,284
47	(538) Electric Expenses	278,163	248,113
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,916,301	2,645,772
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	7,526,489	7,765,218
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	61,778	79,651
54	(542) Maintenance of Structures	316,883	356,818
55	(543) Maintenance of Reservoirs, Dams, and Waterways	515,032	348,801
56	(544) Maintenance of Electric Plant	1,198,621	1,172,419
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,392,652	3,170,658
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	5,484,966	5,128,347
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	13,011,455	12,893,565
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	5,767,407	5,144,609
63	(547) Fuel	290,270,276	232,657,565
64	(548) Generation Expenses	14,012,624	13,507,698
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	4,076,263	3,358,743
66	(550) Rents	6,982,021	8,475,624
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	321,108,591	263,144,239
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	395,881	403,339
70	(552) Maintenance of Structures	744,224	666,196
71	(553) Maintenance of Generating and Electric Plant	32,559,417	27,195,709
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,249,908	1,361,703
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	34,949,430	29,626,947
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	356,058,021	292,771,186
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,043,007,858	691,169,391
76.1	(555.1) Power Purchased for Storage Operations	0	
77	(556) System Control and Load Dispatching	28,612	28,612
78	(557) Other Expenses	(11,850,062)	21,519,727
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	1,031,186,408	712,717,730
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	1,495,911,944	1,106,876,461
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,459,252	3,255,173
85	(561.1) Load Dispatch-Reliability	43,541	44,637
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,084,722	2,185,291
87	(561.3) Load Dispatch-Transmission Service and Scheduling	941,407	984,985
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	1,835,915	1,804,142
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	2,476,217	1,515,064
92	(561.8) Reliability, Planning and Standards Development Services	66,314	89,552
93	(562) Station Expenses	1,288,208	1,256,091
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	390,690	313,896

95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	144,916,422	125,928,844
97	(566) Miscellaneous Transmission Expenses	3,305,489	3,292,610
98	(567) Rents	398,644	340,954
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	161,206,821	141,011,239
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	21,613	38,111
102	(569) Maintenance of Structures	1,205	662
103	(569.1) Maintenance of Computer Hardware	41	31
104	(569.2) Maintenance of Computer Software	4,470	112,248
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,371,329	2,896,323
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	7,339,307	6,827,772
109	(572) Maintenance of Underground Lines		481,907
110	(573) Maintenance of Miscellaneous Transmission Plant	100,742	71,719
111	TOTAL Maintenance (Total of Lines 101 thru 110)	9,838,707	10,428,773
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	171,045,528	151,440,012
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	3,845,379	3,751,035
135	(581) Load Dispatching	1,233,905	1,669,736
136	(582) Station Expenses	2,046,281	1,781,545
137	(583) Overhead Line Expenses	4,788,508	3,399,350
138	(584) Underground Line Expenses	5,860,854	4,956,449
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	3,538,416	2,131,373
141	(587) Customer Installations Expenses	5,698,726	4,583,670
142	(588) Miscellaneous Expenses	10,714,945	8,598,697
143	(589) Rents	1,450,313	1,182,070
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	39,177,327	32,053,925

145	Maintenance		
146	(590) Maintenance Supervision and Engineering	136,537	171,228
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	2,071,574	2,474,060
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	40,470,707	42,082,560
150	(594) Maintenance of Underground Lines	13,977,521	13,059,750
151	(595) Maintenance of Line Transformers	724,550	125,731
152	(596) Maintenance of Street Lighting and Signal Systems	2,984,435	2,823,425
153	(597) Maintenance of Meters	720,967	739,012
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of Lines 146 thru 154)	61,086,291	61,475,766
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	100,263,618	93,529,691
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	123,215	125,122
160	(902) Meter Reading Expenses	12,142,113	12,645,378
161	(903) Customer Records and Collection Expenses	24,224,347	22,865,514
162	(904) Uncollectible Accounts	18,549,268	18,706,364
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	55,038,943	54,342,378
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	132,966,770	109,281,723
169	(909) Informational and Instructional Expenses	1,882,235	2,188,567
170	(910) Miscellaneous Customer Service and Informational Expenses		176
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	134,849,005	111,470,466
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	969,613	785,859
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	969,613	785,859
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	69,794,998	59,104,027
182	(921) Office Supplies and Expenses	5,878,079	8,970,630
183	(Less) (922) Administrative Expenses Transferred-Credit	27,808,615	24,908,554
184	(923) Outside Services Employed	16,764,046	16,819,393
185	(924) Property Insurance	6,082,479	5,294,417
186	(925) Injuries and Damages	5,217,662	6,364,506
187	(926) Employee Pensions and Benefits	30,682,128	35,236,181
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	18,424,521	10,013,719
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	55,714	17,479
192	(930.2) Miscellaneous General Expenses	7,615,337	8,093,308
193	(931) Rents	9,673,159	8,118,639
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	142,379,508	133,123,745
195	Maintenance		

196	(935) Maintenance of General Plant	17,767,627	17,797,323
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	160,147,135	150,921,068
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	2,118,225,786	1,669,365,935

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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): 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)	COST/SETTLEMENT OF POWER: Demand Charges ($) (k)	COST/SETTLEMENT OF POWER: Energy Charges ($) (l)	COST/SETTLEMENT OF POWER: Other Charges ($) (m)	COST/SETTLEMENT OF POWER: Total (k+l+m) of Settlement ($) (n)
1	[a] 3 Bar G Wind Turbine #3 LLC	LU					72					2,095		2,095
2	[b] Avangrid Renewable (Golden Hills)	LU					408,537					18,267,591		18,267,591
3	Avista Corp. WWP Division	OS					50,554					2,840,868		2,840,868
4	[c] Avista Nichols Pump	EX							21,151	0		1,154,053		1,154,053
5	[d] Powerex (Point Roberts)	IF					20,550					1,348,791		1,348,791
6	[e] BIO ENERGY (Washington) LLC	LU					4					148		148
7	[f] Black Creek Hydro	LU					5,960					300,329		300,329
8	[g] Bloks Evergreen Dairy	LU					107					7,560		7,560
9	[h] BP Energy Co.	AD					16						1,844	1,844
10	BP Energy Co.	OS					60,636					2,245,618		2,245,618
11	[i] Bonneville Power Admistration	LF										9,432,000		9,432,000
12	Bonneville Power Admistration	OS					829,294					52,996,305		52,996,305
13	Brookfield Energy Marketing LP	OS					35,320					5,386,012		5,386,012
14	[j] CA Carbon Obligation	AD											717,674	717,674
15	[k] California ISO - EIM Purchases	AD											(96,856)	(96,856)

16	California ISO - EIM Purchases	OS					838,627					48,432,590		48,432,590
17	California ISO	OS					16,535					1,705,372		1,705,372
18	[l] CAMAS SOLAR	LU					4,649					329,887		329,887
19	[m] Cascade Community Solar	OS					29					722		722
20	[n] Chelan County PUD #1	AD											400	400
21	Chelan County PUD #1	OS					74,041					3,681,063		3,681,063
22	[o] Chelan PUD - Rock Island and Rocky Reach	LU					2,572,112					49,567,487	42,181,451	91,748,938
23	[p] Citigroup Energy (Financial)	OS										(1,513,069)		(1,513,069)
24	Citigroup Energy Inc	OS					344,618					18,142,787		18,142,787
25	City of Roseville	OS					1,900					54,344		54,344
26	[q] Clatskanie PUD	AD					35						875	875
27	Clatskanie PUD	OS					3,086					256,120		256,120
28	[r] Clearwater Wind	LU					212,049					5,665,949		5,665,949
29	[s] Conoco, Inc.	AD					44						2,635	2,635
30	Conoco, Inc.	OS					1,399,746					126,274,637		126,274,637
31	[t] CONSTELLATION ENERGY	AD					121						30,367	30,367
32	CONSTELLATION ENERGY	OS					883,427					73,978,444		73,978,444
33	CP Energy Marketing (Epcor)	OS					7,343					1,072,720		1,072,720
34	System Deviation	EX							50,800	178,631				
35	[u] Douglas County PUD #1	AD											89,090	89,090
36	Douglas County PUD #1	OS										4,750,694		4,750,694
37	[v] Douglas PUD - Wells Project	IU					231,936					8,340,000		8,340,000
38	[w] Douglas PUD - Wells Project	AD											(59,623)	(59,623)
39	[x] Douglas PUD - Wells Project	LU					1,083,200					34,368,022		34,368,022
40	DYNASTY POWER INC	OS					6,500					1,053,215		1,053,215
41	[y] Edaleen Dairy, LLC	OS					3,677					122,296		122,296
42	EDF Trading NA LLC	OS					3,474					150,788		150,788
43	[z] Emerald City Renewables, LLC	LU					31,788					2,283,353		2,283,353
44	[aa] Energy Keepers Inc.	AD					12						205	205
45	Energy Keepers Inc.	OS					1,008					57,543		57,543
46	[ab] Eugene Water & Electric	AD					(35)						(875)	(875)
47	Eugene Water & Electric	OS					7,498					452,561		452,561
48	[ac] EV Operating/power cost deferral	AD											(1,676)	(1,676)
49	[ad] Farm Power Rexville LLC	OS					3,792					126,138		126,138
50	Grant County PUD #2	OS					8,607					300,271		300,271
51	[ae] Grant PUD - Priest Rapids Project	AD											64,825	64,825
52	[af] Grant PUD - Priest Rapids Project	LU					464,646					22,496,259		22,496,259

53	[ag] Green Direct RECs	AD											1,105,493	1,105,493
54	Gridforce Energy Management, LLC.	OS					7					942		942
55	Avangrid Renewables (PPM Energy)	OS					777,607					59,154,147		59,154,147
56	[ah] Idaho Power Company	AD					124						21,615	21,615
57	Idaho Power Company	OS					5,537					327,899		327,899
58	[ai] Ikea U.S. West, Inc.	LU					31					2,227		2,227
59	[aj] KERR DAM-ENERGY KEEPER	LU					350,341					16,641,198		16,641,198
60	[ak] Avangrid Renewables (Klondike Wind Power III)	AD											60,549	60,549
61	[al] Avangrid Renewables (Klondike Wind Power III)	LU					118,007					8,455,361		8,455,361
62	[am] Knudsen Wind Turbine#1	LU					78					2,259		2,259
63	[an] Koma Kulshan Associates	AD											(1)	(1)
64	[ao] Koma Kulshan Associates	LU					30,247					2,535,781		2,535,781
65	[ap] Lake Washington School District #414	OS					219					5,450		5,450
66	[aq] Lund Hill Solar, LLC	AD											1,804	1,804
67	[ar] Lund Hill Solar, LLC	LU					345,989					13,183,659		13,183,659
68	MERCURIA ENERGY	OS					3,407					991,449		991,449
69	[as] Mitsui Bussan (Financial)	OS										(6,571)		(6,571)
70	[at] Morgan Stanley CG	AD					(131)						(17,110)	(17,110)
71	[au] Morgan Stanley CG	LF					244,785					11,615,048		11,615,048
72	Morgan Stanley CG	OS					35,832					2,479,071		2,479,071
73	[av] Morgan Stanley CG (Financial)	OS										(3,401,980)		(3,401,980)
74	Nevada Energy	OS					200					22,800		22,800
75	NextEra Energy Power Marketing	OS					4,320					180,437		180,437
76	[aw] Puget Sound Hydro (Nooksack)	OS					15,282					508,276		508,276
77	Northwestern Energy	OS					26,859					1,499,467		1,499,467
78	[ax] Pacific Gas & Elec - Exchange	EX							413,000	413,000				
79	Pacificorp	OS					12,967					986,790		986,790
80	[ay] Penstemon Solar	LU					10,069					714,488		714,488
81	[az] Port of Coupeville	OS					58					1,455		1,455
82	Portland General Electric	OS					42,077					3,147,256		3,147,256
83	Powerex Corp.	OS					108,213					8,192,812		8,192,812
84	[ba] Powerex Summer Capacity	IF					488,000					51,069,200		51,069,200
85	[bb] Powerex Winter Capacity	IF					488,000					57,559,600		57,559,600
86	Public Service of Colorado	OS					3					66		66
87	Rainbow Energy Marketing	OS					5,396					411,275		411,275

88	[bc] Rainer BioGas	OS					3,154					104,906		104,906
89	[bd] Residential Exchange	AD											(77,714,734)	(77,714,734)
90	Sacramento Municipal	OS					200					13,600		13,600
91	[be] Seattle City Light Marketing	AD					(18)						(635)	(635)
92	Seattle City Light Marketing	OS					37,232					3,048,555		3,048,555
93	[bf] Shell Energy (Coral Pwr)	AD					(638)						(23,672)	(23,672)
94	Shell Energy (Coral Pwr)	OS					260,623					11,438,401		11,438,401
95	[bg] Sierra Pacific Industries	AD											(22,197)	(22,197)
96	[bh] Sierra Pacific Industries	LU					83,814					3,616,154		3,616,154
97	[bi] Skookumchuck Hydro	LU					4,809					197,332		197,332
98	[bj] Skookumchuck Wind PPA	LU					312,450					14,530,360		14,530,360
99	Snohomish County PUD #1	OS					13,730					374,082		374,082
100	[bk] Swauk Wind LLC	AD											596	596
101	[bl] Swauk Wind LLC	OS					7,940					230,406		230,406
102	[bm] Hillside Clean Energy (Sygitowicz)	LU					563					39,949		39,949
103	[bn] TACOMA GLASS	OS					115					2,680		2,680
104	Tacoma Power	OS					20,369					1,449,944		1,449,944
105	Tenaska Power Services Co.	OS					32					320		320
106	The Energy Authority	OS					44,098					2,863,327		2,863,327
107	[bo] Transalta Centralia Generation LLC	LU					3,328,032					187,035,399		187,035,399
108	[bp] TransAlta Energy Marketing	AD					(409)						(14,345)	(14,345)
109	TransAlta Energy Marketing	OS					992,660					96,544,889		96,544,889
110	TransCanada Energy Sales Ltd	OS					150					9,750		9,750
111	Turlock Irrigation District	OS					3,412					219,788		219,788
112	[bq] Twin Falls Hydro	LU					70,262					5,269,633		5,269,633
113	[br] URTICA SOLAR	LU					204					14,496		14,496
114	[bs] VanderHaak Dairy Digester	IU					2,514					83,625		83,625
115	Vitol Inc.	OS					5,470					633,646		633,646
116	[bt] South Fork II Associates(Weeks Falls)	OS					12,447					919,629		919,629
117	[bu] Wells Fargo (Financial)	OS										15,627,862		15,627,862
15	TOTAL						17,932,254		484,951	591,631		1,076,680,158	(33,672,301)	1,043,007,857

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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

(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Avangrid Renewable (Golden Hills) Contract Expires Apr, 2042

(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Avista Nichols Pump Contract Expires Oct, 2023

(d) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Powerex (Point Roberts) Contract Expires Sep, 2025

(e) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

BIO ENERGY (Washington) LLC Contract Expires Dec, 2026

(f) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Black Creek Hydro Contract Expires Dec, 2032

(g) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Bloks Evergreen Dairy Contract Expires Dec, 2031

(h) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

BP Energy Co. Prior Period Adjustment

(i) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Bonneville Power Admistration Contract Expires Dec, 2026

(j) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

CA Carbon Allowance

(k) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

CAISO - EIM Purchases Prior Period Adjustment

(l) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

CAMAS SOLAR Contract Expires Dec, 2036

(m) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Cascade Community Solar Contract Expired Dec, 2022

(n) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Chelan County PUD #1 Prior Period Adjustment

(o) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Chelan PUD - Rock Island and Rocky Reach Contract Expires Oct, 2031Administrative $10,017,299 Amortization $ 7,650,871 Debt Service $17,129,616RECs $ 7,383,665Grand Total $42,181,451

(p) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Citigroup Energy Power Financial Hedging Transactions

(q) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Clatskanie PUD Prior Period Adjustment

(r) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Clearwater Wind Contract Expires Nov, 2047

(s) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Conoco, Inc. Prior Period Adjustment

(t) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

CONSTELLATION ENERGY Prior Period Adjustment

(u) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Douglas County PUD #1 Prior Period Adjustment

(v) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Douglas PUD - Wells Project Contract Expires Sep, 2024

(w) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Douglas PUD - Wells Project Prior Period Adjustment

(x) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Douglas PUD - Wells Project Contract Expires Sep, 2028

(y) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Edaleen Dairy, LLC Contract Expired Dec, 2022

(z) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Emerald City Renewables, LLC Contract Expires Dec, 2029

(aa) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Energy Keepers Inc. Prior Period Adjustment

(ab) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Eugene Water & Electric Prior Period Adjustment

(ac) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

EV Operating/power cost deferral

(ad) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Farm Power Rexville LLC Contract Expired Dec, 2022

(ae) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Grant PUD - Priest Rapids Project Prior Period Adjustment

(af) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Grant PUD - Priest Rapids Project Contract Expires Apr, 2052

(ag) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Green Direct RECs

(ah) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Idaho Power Company Prior Period Adjustment
(ai) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Ikea U.S. West, Inc. Contract Expires Dec, 2031
(aj) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
KERR DAM-ENERGY KEEPER Contract Expires Jul, 2035
(ak) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Avangrid Renewables (Klondike Wind Power III) Prior Period Adjustment
(al) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Avangrid Renewables (Klondike Wind Power III) Contract Expires Nov, 2027
(am) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Knudsen Wind Turbine#1 Contract Expires Dec, 2029
(an) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Koma Kulshan Associates Prior Period Adjustment
(ao) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Koma Kulshan Associates Contract Expires Mar, 2037
(ap) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Lake Washington School District #414 Contract Expired Dec, 2022
(aq) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Lund Hill Solar, LLC Prior Period Adjustment
(ar) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Lund Hill Solar, LLC Contract Expires Oct, 2042
(as) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Mitsui Bussan Power Financial Hedging Transactions
(at) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Morgan Stanley CG Prior Period Adjustment
(au) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Morgan Stanley CG Contract Expires Dec, 2026
(av) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Morgan Stanley CG Power Financial Hedging Transactions
(aw) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Puget Sound Hydro (Nooksack) Contract Expired Dec, 2022
(ax) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Pacific Gas & Elec - Exchange Contract Expires Dec, 2027
(ay) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Penstemon Solar Contract Expires Dec, 2036
(az) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Port of Coupeville Contract Expired Dec, 2022
(ba) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Powerex Corp. Contract Expires Sep, 2024
(bb) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Powerex Corp. Contract Expires Mar, 2024
(bc) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Rainer BioGas Contract Expired Dec, 2022
(bd) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Residential Exchange
(be) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Seattle City Light Marketing Prior Period Adjustment
(bf) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Shell Energy (Coral Pwr) Prior Period Adjustment
(bg) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Sierra Pacific Industries Prior Period Adjustment
(bh) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Sierra Pacific Industries Contract Expires Dec, 2037
(bi) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Skookumchuck Hydro Contract Expires Dec, 2025
(bj) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Skookumchuck Wind PPA Contract Expires Nov, 2040
(bk) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Swauk Wind Prior Period Adjustment
(bl) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Swauk Wind LLC Contract Expired Dec, 2022
(bm) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Hillside Clean Energy (Sygitowicz) Contract Expires Dec, 2030
(bn) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
TACOMA GLASS Contract Expires Apr, 2023
(bo) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Transalta Centralia Generation LLC Contract Expires Dec, 2025
(bp) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
TransAlta Energy Marketing Prior Period Adjustment
(bq) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Twin Falls Hydro Contract Expires Feb, 2025
(br) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
URTICA SOLAR Contract Expires Dec, 2036

(bs) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
VanderHaak Dairy Digester Contract Expires Dec, 2023
(bt) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
South Fork II Associates(Weeks Falls) Contract Expired Dec, 2022
(bu) 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: 04/14/2023	Year/Period of Report End of: 2022/ 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)	TRANSFER OF ENERGY: Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS: Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	OS	[(w)] FRS #60	Beverly Park Substn	Goldbar Substation	[(ac)]0					[(ap)]600	600
2	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	[(a)] OLF	[(x)] FRS #28	Beverly Park Substn	Hilton Lake Substn	[(ad)]0	71,102	71,102	11,026		[(aq)]600	11,626
3	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	[(b)] OLF	[(y)] FRS #28	Beverly Park Substn	Olympic Pipe Substn	[(ae)]0	10,831	10,831	1,533		[(ar)]600	2,133
4	Tacoma City Light	Tacoma City Light	Tacoma City Light	[(c)] OS	[(z)] FRS #62	Starwood Substation	Baldi Substation	[(af)]0					[(as)]4,576	4,576
5	Bonneville Power Administration	Bonneville Power Admin	City of Blaine	FNO	[(aa)] PSE OATT	Custer Substation	Blaine&Semiahmo Sub	[(ag)]0	86,746	86,746	379,825		[(at)]378,306	758,131
6	Bonneville Power Administration	Bonneville Power Admin	City of Sumas	FNO	PSE OATT	Bellingham Substn	City of Sumas Sub	[(ah)]0	35,085	35,085	139,383		[(au)]295,288	434,671
7	Bonneville Power Administration	Bonneville Power Admin	Kittitas County PUD	FNO	PSE OATT	White River Substn	Teanaway Substation	[(ai)]0	23,278	23,278	117,967		[(av)]109,710	227,677
8	Bonneville Power Administration	Bonneville Power Admin	Orcas Power & Light	FNO	PSE OATT	Murray Bellingham	Fidalgo Substation	[(aj)]0	242,657	242,657	1,222,401		[(aw)]601,983	1,824,384
9	Bonneville Power Administration	Bonneville Power Admin	Tanner Electric Cooperative	FNO	PSE OATT	Maple Valley Substn	Ames Lake Tap	[(ak)]0	23,230	23,230	106,549		[(ax)]75,609	182,158
10	Bonneville Power Administration	Bonneville Power Admin	Tanner Electric Cooperative	FNO	PSE OATT	Olympia Substation	Luhr Beach Tap	[(al)]0	16,138	16,138	85,010		[(ay)]87,344	172,354
11	Bonneville Power Administration	Bonneville Power Admin	Tanner Electric Cooperative	FNO	PSE OATT	Maple Valley Substn	North Bend Substn	[(am)]0			86,159		[(az)]144,477	230,636
12	Bonneville Power Administration	Bonneville Power Admin	Port of Seattle and Various	FNO	PSE OATT	Various	Sea Tac Airport	[(an)]0	143,308	143,308	500,346		[(ba)]512,890	1,013,236
13	Bonneville Power Administration	Bonneville Power Admin	Lewis County PUD	FNO	PSE OATT	BPAT.PSEI	Tono Substation	[(ao)]0	1,354	1,354	8,189		[(bb)]9,597	17,786
14	Morgan Stanley Capital Group, Inc.	Various	Various	[(d)] LFP	PSE OATT	John Day, COB	John Day, COB	100	876,000	876,000	899,510		[(bc)]874,810	1,774,320
15	Morgan Stanley Capital Group	Various	Various	[(e)] LFP	PSE OATT	Various Washington	Various Washington	90	788,400	788,400	2,576,699		[(bd)] 2,607,368	5,184,067
16	Powerex	Various	Various	[(f)] LFP	PSE OATT	John Day, COB	John Day, COB	225	1,961,016	1,961,016	2,014,329		[(be)] 1,003,350	3,017,679
17	Powerex.	Various	Various	[(g)] LFP	PSE OATT	Various Washington	Various Washington						[(bf)]20,445	20,445
18	Powerex..	Various	Various	[(h)] LFP	PSE OATT	Various Washington	Various Washington	88	770,880	770,880	2,520,760		[(bg)] 1,211,810	3,732,570

19	Seattle City Light	Various	Various	[i] LFP	PSE OATT	Various Washington	Various Washington	16	140,160	140,160	458,320		[bh]37,696	496,016
20	TransAlta Energy	Various	Various	[j] LFP	PSE OATT	John Day, COB	John Day, COB	75	657,000	657,000	674,633		[bi]486,960	1,161,593
21	Vantage Wind Energy LLC-Invenergy	Various	Various	[k] LFP	PSE OATT	Various Washington	Various Washington				1,351		[bj]55	1,406
22	Whatcom County PUD	Whatcom County PUD	Whatcom County PUD	[l] LFP	PSE OATT	Custer Substation	Enterprise Sub	2	17,522	17,522	57,290		[bk]27,972	85,262
23	Brookfield Renewables	Various	Various	SFP	PSE OATT	Various Washington	Various Washington	185	24,384	24,384	77,117		[bl]8,151	85,268
24	Shell Energy North America	Various	Various	SFP	PSE OATT	Various Washington	Various Washington	645	41,748	41,748	140,379		[bm]182,869	323,248
25	Exelon Generation	Various	Various	SFP	PSE OATT	John Day, COB	John Day, COB	12	288	288	350		[bn]850	1,200
26	Guzman Energy	Various	Various	SFP	PSE OATT	John Day, COB	John Day, COB	6	288	288	329		[bo]189	518
27	Avangrid Renewables	Various	Various	SFP	PSE OATT	John Day, COB	John Day, COB	24	9,936	9,936	9,521		[bp]1,375	10,896
28	Powerex	Various	Various	SFP	PSE OATT	John Day, COB	John Day, COB	6	720	720	822		[bq]116	938
29	Powerex	Various	Various	SFP	PSE OATT	Various Washington	Various Washington	559	13,776	13,776	47,948		[br]8,434	56,382
30	Snohomish County PUD	Various	Various	SFP	PSE OATT	Various Washington	Various Washington	352	9,789	9,789	38,931		[bs]16,431	55,362
31	The Energy Authority	Various	Various	SFP	PSE OATT	John Day, COB	John Day, COB						[bt](6,433)	(6,433)
32	Avista Corporation	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		700	700		772	[bu]964	1,736
33	Brookfield Renewables	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		943	943		1,207	[bv]1,064	2,271
34	Brookfield Renewables	Various	Various	NF	PSE OATT	Various Washington	Various Washington		59	59		205	[bw]75	280
35	Shell Energy North America	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		20,317	20,317		31,475	[bx]25,096	56,571
36	Shell Energy North America	Various	Various	NF	PSE OATT	Various Washington	Various Washington		130,656	130,656		567,629	[by]425,560	993,189
37	Dynasty Power Inc	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		111,179	111,179		139,134	[bz]71,993	211,127
38	Dynasty Power Inc	Various	Various	NF	PSE OATT	Various Washington	Various Washington		250	250		1,333	[ca]748	2,081
39	CP Energy Marketing	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		1	1		2	[cb]1	3
40	Exelon Generation	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		19,928	19,928		24,561	[cc]18,950	43,511
41	Exelon Generation	Various	Various	NF	PSE OATT	Various Washington	Various Washington		88	88		469	[cd]69	538
42	Guzman Energy	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		105,572	105,572		120,748	[ce]52,831	173,579
43	Guzman Energy	Various	Various	NF	PSE OATT	Various Washington	Various Washington		150	150		457	[cf]359	816
44	Macquarie Energy, LLC	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		5,653	5,653		7,709	[cg]9,511	17,220
45	Mercuria Energy	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		70,195	70,195		79,774	[ch]55,299	135,073
46	Morgan Stanley Capital Group, Inc.	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		9,715	9,715		16,103	[ci]86,502	102,605
47	Portland General Electric Company	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		101,858	101,858		138,628	[cj]96,974	235,602
48	Powerex	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		97,043	97,043		136,926	[ck]65,141	202,067
49	Powerex	Various	Various	NF	PSE OATT	Various Washington	Various Washington		31,231	31,231		132,518	[cl]77,400	209,918
50	Rainbow Energy Marketing	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		27,758	27,758		33,447	[cm]41,255	74,702
51	Seattle City Light	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		160	160		296	[cn]36	332
52	Snohomish County PUD	Various	Various	NF	PSE OATT	Various Washington	Various Washington		4,207	4,207		19,306	[co]8,774	28,080
53	The Energy Authority	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		174,578	174,578		245,873	[cp]344,399	590,272

54	The Energy Authority	Various	Various	NF	PSE OATT	Various Washington	Various Washington		366	366		1,810	[cq]2,650	4,460
55	TransAlta Energy	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		8,214	8,214		10,918	[cr]8,190	19,108
56	TransAlta Energy	Various	Various	NF	PSE OATT	Various Washington	Various Washington		1	1		5	[cs]2	7
57	Tacoma Power	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		1	1		2	[ct]1	3
58	Vitol, Inc.	Various	Various	NF	PSE OATT	John Day, COB	John Day, COB		13,294	13,294		16,946	[cu]17,502	34,448
59	Air Liquide	Various	Air Liquide	[m] FNO	PSE OATT	[ab] Rocky Reach 115KV Sw	Air Liquide		73,298	73,298	241,762		[cv]186,416	428,178
60	Air Products	Various	Air Products	[n] FNO	PSE OATT	Rocky Reach 115KV Sw	Air Products		51,196	51,196	144,626		[cw]128,129	272,755
61	AMCOR Rigid Plastics USA	Various	AMCOR Rigid Plastics USA	[o] FNO	PSE OATT	Rocky Reach 115KV Sw	AMCOR Rigid Plastics		46,407	46,407	137,804		[cx]181,785	319,589
62	Bellingham Cold Storage - Roeder	Various	Bellingham Cold Storage - Roeder	[p] FNO	PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Roed		19,161	19,161	71,129		[cy]57,533	128,662
63	Bellingham Cold Storage - Orchard	Various	Bellingham Cold Storage - Orchar	[q] FNO	PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Orch		19,310	19,310	68,074		[cz]54,351	122,425
64	Boeing	Various	Boeing	[r] FNO	PSE OATT	Rocky Reach 115KV Sw	Boeing		365,002	365,002	1,257,760		[da] 1,123,522	2,381,282
65	BP Products North America Inc	Various	BP Products North America	[s] FNO	PSE OATT	Rocky Reach 115KV Sw	BP Products North America Inc		804,069	804,069	2,655,189		[db] 2,077,314	4,732,503
66	Center Drive Owners Association	Various	Center Drive Owners	[t] FNO	PSE OATT	Rocky Reach 115KV Sw	Center Drive Owners		4,137	4,137	14,716		[dc]18,800	33,516
67	HollyFrontier Puget Sound Refining	Various	HollyFrontier	[u] FNO	PSE OATT	Rocky Reach 115KV Sw	HollyFrontier		329,859	329,859	1,048,867		[dd] 1,020,398	2,069,265
68	Tesoro Refining & Marketing CMP	Various	Tesoro	[v] FNO	PSE OATT	Rocky Reach 115KV Sw	Tesoro		277,870	277,870	914,076		[de]807,487	1,721,563
69	Shell Oil Products (Equilon)	Various	Shell (Equilon)	FNO	PSE OATT	Various Washington	Various Washington						[df](293)	(293)
70	Air Liquide	Various	Air Liquide	AD	PSE OATT	Rocky Reach 115KV Sw	Air Liquide						[dg](1)	(1)
71	BP Products North America Inc	Various	BP Products North America	AD	PSE OATT	Rocky Reach 115KV Sw	BP Products North America						[dh](7)	(7)
72	Boeing	Various	Various	AD	PSE OATT	Various Washington	Various Washington						[di](4)	(4)
73	Bonneville Power Administration	Various	Various	AD	PSE OATT	Various Washington	Various Washington						[dj](7)	(7)
74	Morgan Stanley Capital	Various	Various	AD	PSE OATT	Various Washington	Various Washington						[dk](14)	(14)
75	Portland General Electric	Various	Various	AD	PSE OATT	Various Washington	Various Washington						[dl](1)	(1)
76	Powerex	Various	Various	AD	PSE OATT	Various Washington	Various Washington						[dm](26)	(26)
77	Seattle City Light	Various	Various	AD	PSE OATT	Various Washington	Various Washington						[dn](1)	(1)
78	Shell Oil Products (Equilon)	Various	Shell (Equilon)	AD	PSE OATT	Various Washington	Various Washington						[do](3)	(3)
79	Sierra Pacific Industries	Various	Various	AD	PSE OATT	Various Washington	Various Washington						[dp](1)	(1)
80	The Energy Authority	Various	Various	AD	PSE OATT	Various Washington	Various Washington						[dq](1)	(1)
81	TransAlta Energy	Various	Various	AD	PSE OATT	Various Washington	Various Washington						[dr](6)	(6)
82	Tesoro	Various	Tesoro	AD	PSE OATT	Various Washington	Various Washington						[ds](2)	(2)
35	TOTAL							2,385	8,890,062	8,890,062	18,730,680	1,728,253	15,770,742	36,229,675

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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, 2023; 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, 2023; 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 July 1, 2025.

(l) Concept: StatisticalClassificationCode

Contract expires with one year written notice.

(m) Concept: StatisticalClassificationCode

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

(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 459.

(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 449.

(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 459.

(w) Concept: RateScheduleTariffNumber

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

(x) 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.

(y) 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.

(z) 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.

(aa) 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.

(ab) Concept: TransmissionPointOfReceipt

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

(ac) Concept: BillingDemand

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

(ad) 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.

(ae) 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.

(af) 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.

(ag) Concept: BillingDemand

Billing demand is based on monthly peak consistent with Puget Sound Energy’s OATT.

(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
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(ak) Concept: BillingDemand
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(al) Concept: BillingDemand
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(am) Concept: BillingDemand
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(an) 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: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities charges.
(aq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities charges.
(ar) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities charges.
(as) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Use of facilities charges.
(at) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax, facilities fees and loss return charges.
(au) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax, facilities fees and loss return charges.
(av) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax, facilities fees and loss return charges.
(aw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(ax) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(ay) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax, facilities fees and loss return charges.
(az) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(ba) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax, facilities fees and loss return charges.
(bb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax, facilities fees and loss return charges.
(bc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(bd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(be) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(bf) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(bg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(bh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(bi) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(bj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(bk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(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
Includes ancillary services and loss return charges.
(bo) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services 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, Washington State tax and loss return charges.

(bs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(bt) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Loss return for prior year adjusment
(bu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(bv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(bw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(bx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(by) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(bz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(ca) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(cb) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(ce) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cf) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(cg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(ch) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(ci) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(ck) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(cm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(co) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(cp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(cr) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(ct) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services and loss return charges.
(cv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(cw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax and loss return charges.
(cx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes ancillary services, Washington State tax 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
Includes ancillary services, Washington State tax and loss return charges.
(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
Loss return for prior year adjusment
(dg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty charges.
(dh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Distribution of prior year unreserved use penalty 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
Distribution of prior year unreserved use penalty charges.
(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.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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					
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48					
49					
40	TOTAL				

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 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)
1	Bonneville Power Admin	[(a)] LFP	[(e)] 0		[(g)] 40,057,056		[(i)] 7,680,036	47,737,092
2	Bonneville Power Admin	[(b)] LFP	[(f)] 19,242,703	19,242,703	[(h)] 54,924,928		[(j)] 24,161,889	79,086,817
3	Bonneville Power Admin	SFP			11,600			11,600
4	Bonneville Power Admin	NF	793	793	14,000	5,979	[(k)] 732	20,711
5	Bonneville Power Admin	OS					[(l)] 10,450	10,450
6	Bonneville Power Admin	OS					[(m)] 7,085	7,085
7	Bonneville Power Admin	OS					[(n)] 6,082,965	6,082,965
8	Bonneville Power Admin	OS					[(o)] 5,000	5,000
9	Bonneville Power Admin	OS					[(p)] 5,886,202	5,886,202
10	Bonneville Power Admin	AD					[(q)] (448,700)	(448,700)
11	Brookfield Energy Mrktg	OS					[(r)] (2,238)	(2,238)
12	Chelan County PUD No. 1	[(c)] OLF	2,714,683	2,714,683			[(s)] 5,709,624	5,709,624
13	ConocoPhillips Co.	OS					[(t)] (223,256)	(223,256)
14	Avista	OS					[(u)] 933	933
15	Dynasty Power Inc.	OS					[(v)] (12,482)	(12,482)
16	Avista	NF	600	600		3,170		3,170
17	Grant County PUD No. 2	OS					[(w)] 143,352	143,352
18	Iberdrola Renewables	OS					[(x)] (101,908)	(101,908)
19	Idaho Power Company	OS					[(y)] (254,601)	(254,601)
20	Klickitat County PUD	[(d)] OLF	1,591,661	1,591,661			[(z)] 1,380,996	1,380,996
21	Klondike Wind Power lll	OS					[(aa)] 377,665	377,665
22	Klondike Wind Power lll	AD					[(ab)] 452	452
23	Morgan Stanley CG	OS					[(ac)] (458,758)	(458,758)
24	Idaho Power Company	NF	201	201		1,007		1,007
25	NorthWestern Energy	SFP	12,528	12,528	53,374		[(ad)] 1,377	54,751
26	NorthWestern Energy	NF	23,311	23,311		111,216	[(ae)] 3,499	114,715
27	NorthWestern Energy	OS					[(af)] 407,175	407,175
28	NorthWestern Energy	AD					[(ag)] (32,425)	(32,425)
29	Northwestern Energy	OS					[(ah)] 84,452	84,452
30	EDF Trading	OS					[(ai)] (8,986)	(8,986)
31	Portland General Elec	NF	625	625		2,453		2,453
32	Portland General Elec	AD						
33	Powerex Corp	OS					[(aj)] (391,700)	(391,700)
34	Rainbow Energy Mrketing	OS					[(ak)] (300)	(300)
35	Seattle City Light	OS					[(al)] 105,366	105,366
36	Shell Energy	OS						
37	Snohomish County PUD # 1	OS					[(am)] 48,386	48,386

38	Tacoma Power	OS					[an](31,500)	(31,500)
39	Talen Energy Marketing	NF						
40	Talen Energy Marketing	OS					[ao]727,282	727,282
41	The Energy Authority	OS					[ap](457,944)	(457,944)
42	The Energy Authority	AD						
43	TransAlta Energy Mrktng	OS					[aq]670,179	670,179
44	TransAlta Energy Mrktng	OS					[ar](1,346,436)	(1,346,436)
45	TransAlta Energy Mrktng	AD						
46	Whatcom Co PUD	AD						
47	Whatcom Co PUD	OS					[as]17,219	17,219
48	EIM application fee	OS					[at]1,500	1,500
49	Vitol co.	OS					[au](19,196)	(19,196)
50	Vitol co.	AD					[av]8,254	8,254
	TOTAL		23,587,105	23,587,105	95,060,958	123,825	49,731,639	144,916,422

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode

Includes a contract with several tables with end dates ranging from October 2022 to June 2037.

(b) Concept: StatisticalClassificationCode

Includes a contract with several tables with end dates ranging from July 2022 to March, 2029.

(c) Concept: StatisticalClassificationCode

Contract end date is October 31, 2031.

(d) Concept: StatisticalClassificationCode

Contract end date is June 30, 2032.

(e) Concept: TransmissionOfElectricityByOthersEnergyReceived

Total MWh's for BPA firm transmission is calculated to be 19,242,703. The reporting does not split the MWh'samongst the contracts for the long-term firm Mid-Columbia projects, the other long-term firm contracts and theshort-term firm contracts, so the entire 19,242,703 is reported with the long-term firm contracts on Line 2.,

(f) Concept: TransmissionOfElectricityByOthersEnergyReceived

Total MWh's for BPA firm transmission is calculated to be 19,242,496. The reporting does not split the MWh'samongst the contracts for the long-term firm Mid-Columbia projects, the other long-term firm contracts and theshort-term firm contracts, so the entire 19,242,496 is reported with the long-term firm contracts on Line 2.

(g) Concept: DemandChargesTransmissionOfElectricityByOthers

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

(h) Concept: DemandChargesTransmissionOfElectricityByOthers

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

(i) Concept: OtherChargesTransmissionOfElectricityByOthers

Ancillary services.

(j) 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.

(k) Concept: OtherChargesTransmissionOfElectricityByOthers

Ancillary services

(l) Concept: OtherChargesTransmissionOfElectricityByOthers

BPA NWPP Reserve Sharing Fee

(m) Concept: OtherChargesTransmissionOfElectricityByOthers

Use of facilities charges.

(n) Concept: OtherChargesTransmissionOfElectricityByOthers

Intertie charge and capacity rights charges.

(o) Concept: OtherChargesTransmissionOfElectricityByOthers

BPA Non-refundable fee for Transmission Service Request processing fee.

(p) Concept: OtherChargesTransmissionOfElectricityByOthers

Wind integration and generator imbalance charges.

(q) Concept: OtherChargesTransmissionOfElectricityByOthers

BPA - Prior Period Adjustments:

$	(333,492)	BPA - CA Wind Integration
$	(119,212)	BPA - 3rd AC Capacity Rights
$	4,004	BPA IS - NFP Wheeling
$	**(448,700)**	**Total**

(r) Concept: OtherChargesTransmissionOfElectricityByOthers

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

(s) Concept: OtherChargesTransmissionOfElectricityByOthers

Use of facilities charges.

(t) Concept: OtherChargesTransmissionOfElectricityByOthers

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

(u) Concept: OtherChargesTransmissionOfElectricityByOthers

Avista EIM pass-through charges.

(v) Concept: OtherChargesTransmissionOfElectricityByOthers

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

(w) Concept: OtherChargesTransmissionOfElectricityByOthers

Use of transmission facilities charges.

(x) Concept: OtherChargesTransmissionOfElectricityByOthers

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

(y) Concept: OtherChargesTransmissionOfElectricityByOthers

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

(z) Concept: OtherChargesTransmissionOfElectricityByOthers

Actual cost capacity charges.

(aa) Concept: OtherChargesTransmissionOfElectricityByOthers

Wind integration charges.

(ab) Concept: OtherChargesTransmissionOfElectricityByOthers

Adjustment of prior period wind integration charges.

(ac) Concept: OtherChargesTransmissionOfElectricityByOthers

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

(ad) Concept: OtherChargesTransmissionOfElectricityByOthers

Ancillary services.

(ae) Concept: OtherChargesTransmissionOfElectricityByOthers

Ancillary services.

(af) Concept: OtherChargesTransmissionOfElectricityByOthers

Use of facilities charges.

(ag) Concept: OtherChargesTransmissionOfElectricityByOthers

Northwestern prior period adjustment of transmission charges following tariff rate settlement.

(ah) Concept: OtherChargesTransmissionOfElectricityByOthers
Northwestern EIM pass-through charges.
(ai) Concept: OtherChargesTransmissionOfElectricityByOthers
Reimbursement from EDF Trading for use of PSE capacity on Bonneville Power Administration lines.
(aj) Concept: OtherChargesTransmissionOfElectricityByOthers
Reimbursement from Powerex for use of PSE capacity on Bonneville Power Administration lines.
(ak) Concept: OtherChargesTransmissionOfElectricityByOthers
Reimbursement from Rainbow Energy for use of PSE capacity on Bonneville Power Administration lines.
(al) Concept: OtherChargesTransmissionOfElectricityByOthers
Prepay Amortization charge for Seattle City Light.
(am) Concept: OtherChargesTransmissionOfElectricityByOthers
Annual Beverly Park use of facilities charge
(an) Concept: OtherChargesTransmissionOfElectricityByOthers
Reimbursement from Tacoma Power for use of PSE capacity on Bonneville Power Administration lines.
(ao) Concept: OtherChargesTransmissionOfElectricityByOthers
Premium Amortization.
(ap) Concept: OtherChargesTransmissionOfElectricityByOthers
Reimbursement from The Energy Authority for use of PSE capacity on Bonneville Power Administration lines.
(aq) Concept: OtherChargesTransmissionOfElectricityByOthers
Ancillary services - reserves.
(ar) Concept: OtherChargesTransmissionOfElectricityByOthers
Reimbursement from TransAlta Energy Marketing for use of PSE capacity on Bonneville Power Administration lines.
(as) Concept: OtherChargesTransmissionOfElectricityByOthers
Whatcom inter-connection loss.
(at) Concept: OtherChargesTransmissionOfElectricityByOthers
EIM application fee PSEM to PSEI
(au) Concept: OtherChargesTransmissionOfElectricityByOthers
Reimbursement from Vitol for use of PSE capacity on Bonneville Power Administration lines.
(av) Concept: OtherChargesTransmissionOfElectricityByOthers
Vitol transmission resale prior period adjustment.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	793,889
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	538,752
8	Other Membership Dues	544,411
9	Treasury Fees & Expenses	148,672
10	Misc General Expense - Electric	5,575,015
11	State/Fed Govt Related Industry Expenses	6,598
46	TOTAL	7,615,337

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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			15,941,850		15,941,850
2	Steam Production Plant	42,113,280	5,311,592			47,424,872
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	19,780,971		1,223,498		21,004,469
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	78,787,015	3,218,715			82,005,730
7	Transmission Plant	37,831,774	64,628			37,896,402
8	Distribution Plant	160,411,443	202,028			160,613,471
9	Regional Transmission and Market Operation					
10	General Plant	15,664,669				15,664,669
11	Common Plant-Electric	19,879,231	105,691	52,711,590		72,696,512
12	TOTAL	374,468,383	8,902,654	69,876,938		453,247,975

B. Basis for Amortization Charges

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
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Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 (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	11,286,335		11,286,335		Electric	928	11,286,335				
2	Federal fees:											
3	Upper & Lower Baker Project	2,060,440		2,060,440		Electric	928	2,060,440				
4	Snoqualmie 1 & 2 Project	151,638		151,638		Electric	928	151,638				
5	FERC Regulatory Comm Trading	1,222,627		1,222,627		Electric	928	1,222,627				
6	Other Charges:											
7	FERC Regulatory Legal Fees		281,776	281,776		Electric	928	281,776				
8	State Regulatory Legal Fees		254,848	254,848		Electric	928	254,848				
9	Transmission Rate Case		170,397	170,397		Electric	928	170,397				
10	General Rate Case Legal Fees		3,000,344	3,000,344		Electric	928	3,000,344				
46	TOTAL	14,721,040	3,707,365	18,428,405				18,428,405				

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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:

Electric R, D and D Performed Internally:

- Generation
  - hydroelectric
    - Recreation fish and wildlife
    - Other hydroelectric
  - Fossil-fuel steam
  - Internal combustion or gas turbine
  - Nuclear
  - Unconventional generation
  - Siting and heat rejection
- Transmission
  - Overhead
  - Underground
- Distribution
- Regional Transmission and Market Operation
- Environment (other than equipment)
- Other (Classify and include items in excess of $50,000.)
- Total Cost Incurred

Electric, R, D and D Performed Externally:

- Research Support to the electrical Research Council or the Electric Power Research Institute
- Research Support to Edison Electric Institute
- Research Support to Nuclear Power Groups
- Research Support to Others (Classify)
- 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 2022						

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	24,850,297		
4	Transmission	10,319,321		
5	Regional Market			
6	Distribution	26,373,857		
7	Customer Accounts	8,123,062		
8	Customer Service and Informational	2,392,878		
9	Sales	758,325		
10	Administrative and General	40,571,604		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	113,389,344		
12	Maintenance			
13	Production	4,182,702		
14	Transmission	2,163,255		
15	Regional Market			
16	Distribution	8,836,579		
17	Administrative and General	98,003		
18	TOTAL Maintenance (Total of lines 13 thru 17)	15,280,539		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	29,032,999		
21	Transmission (Enter Total of lines 4 and 14)	12,482,576		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	35,210,436		
24	Customer Accounts (Transcribe from line 7)	8,123,062		
25	Customer Service and Informational (Transcribe from line 8)	2,392,878		
26	Sales (Transcribe from line 9)	758,325		
27	Administrative and General (Enter Total of lines 10 and 17)	40,669,607		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	128,669,883	1,035,104	129,704,987
29	Gas			
30	Operation			
31	Production - Manufactured Gas	65,351		
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply	2,734,150		
34	Storage, LNG Terminaling and Processing	1,099,690		
35	Transmission			
36	Distribution	21,736,736		
37	Customer Accounts	5,838,066		
38	Customer Service and Informational	1,088,685		
39	Sales	(68,110)		
40	Administrative and General	17,562,822		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	50,057,390		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			

45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	303,147		
47	Transmission			
48	Distribution	5,394,526		
49	Administrative and General	91,129		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	5,788,802		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	65,351		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	2,734,150		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	1,402,837		
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	27,131,262		
58	Customer Accounts (Line 37)	5,838,066		
59	Customer Service and Informational (Line 38)	1,088,685		
60	Sales (Line 39)	(68,110)		
61	Administrative and General (Lines 40 and 49)	17,653,951		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	55,846,192	449,263	56,295,455
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	184,516,075	1,484,367	186,000,442
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	76,228,815	613,233	76,842,048
69	Gas Plant	30,720,678	247,136	30,967,814
70	Other (provide details in footnote):	59,809,295	481,145	60,290,440
71	TOTAL Construction (Total of lines 68 thru 70)	166,758,788	1,341,514	168,100,302
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,554,986	20,554	2,575,540
74	Gas Plant	2,324,285	18,698	2,342,983
75	Other (provide details in footnote):	276,568	2,225	278,793
76	TOTAL Plant Removal (Total of lines 73 thru 75)	5,155,839	41,477	5,197,316
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):	[a]28,236,359	227,151	28,463,510
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95	TOTAL Other Accounts	28,236,359	227,151	28,463,510
96	TOTAL SALARIES AND WAGES	384,667,061	3,094,509	387,761,570

FOOTNOTE DATA

(a) Concept: SalariesAndWagesOtherAccounts

Description	Direct Payroll Distribution (b)	Allocation of Payroll Charged to Clearing Accounts (c)	Total (d) (Col-7 + Col8)
121 Non Utility Property	4,506	36	4,542
163 Store Expense	4,322,017	34,769	4,356,786
182 Regulatory Asset	16,664,417	134,058	16,798,475
185 Temporary Facilities	24,942	201	25,143
149 Misc. Deferred Debits	1,568,579	12,619	1,581,198
186 Misc. Deferred Debits	2,940,183	23,653	2,963,836
Misc. 400 Accounts	2,704,387	21,756	2,726,143
143 Accts Receivable Misc.	—	—	—
Prelim Survey OG 183	6,404	52	6,456
Allocated OG 184	—	—	—
Misc. 200 Accounts	924	7	931
Jackson Prairie Joint Venture - Capital - PSE Share	—	—	—
Jackson Prairie Joint Venture - Expense - PSE Share	—	—	—
TOTAL	28,236,359	227,151	28,463,510

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 12/31/2022	ACCUMULATED PROVISION FOR DEPR & AMORT
C302	Franchises	485,094	196,154
C303	Software Development	511,628,585	293,118,745
C389	Land and Land Rights	53,483,328	3,139,536
C390	Structures and Improvements	213,463,030	94,036,854
C391	Office Furniture and Equipment	102,050,632	37,644,604
C392	Transportation Equipment	1,290,036	(571,622)
C393	Stores Equipment	92,576	44,995
C394	Tools/Shop/Garage Equipment	1,511,886	1,161,020
C396	Power Operated Equipment	738,787	421,169
C397	Communication Equipment	142,885,869	40,886,454
C398	Miscellaneous Equipment	647,759	2,199,578
C399	Other Tangible Property	1,258,506	324,099
Total	Common Plant in Service	1,029,536,088	472,601,586

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	30,129,177	19,879,232	10,249,946	(D)
404	Amortization of LTD Term Plant	82,441,488	54,394,894	28,046,594	(D)
901	Customer Accounts and Collection Supervision	211,783	123,215	88,568	(A)
902	Meter Reading Expense	2,227,061	1,396,145	830,917	(B)
903	Customer Records and Collections	25,608,458	14,899,001	10,709,457	(A)
904	Uncollectible Accounts	123,659	81,590	42,069	(D)
908	Customer Assistance	1,840,463	1,070,781	769,682	(A)
909	Information and Instructional Advertising	1,372,941	798,777	574,164	(A)
910	Miscellaneous Customer Services and Information	—	—	—	(A)
912	Common Sales	(232,754)	(135,416)	(97,338)	(A)
920	Administrative and General Salaries	98,523,687	65,005,929	33,517,758	(D)
921	Office Supplies & Expense	2,667,723	1,760,164	907,559	(D)
922	Administrative Expense Transferred	(42,147,037)	(27,808,615)	(14,338,422)	(D)
923	Outside Services Employed	19,705,117	13,001,436	6,703,681	(D)
924	Property Insurance	199,013	117,796	81,217	(C)
925	Injuries & Damages	9,078,685	5,281,979	3,796,706	(A)
928	Regulatory Commission	(225,564)	(148,827)	(76,737)	(D)
930.1	Common Gen Advertising Exp	29,434	19,420	10,013	(D)
930.2	Miscellaneous General Expense	11,707,317	7,724,488	3,982,829	(D)
931	Rents	8,736,420	5,764,290	2,972,130	(D)
935	Maintenance of General Plant	24,831,261	16,383,666	8,447,595	(D)
Total Expense		276,828,331	179,609,943	97,218,388	

(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: 65.98%, and Gas: 34.02%

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: 04/14/2023	Year/Period of Report End of: 2022/ 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)	2,189,796	5,132,913	8,432,170	[a]34,286,228
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(6,182,636)	(6,610,918)	(13,547,717)	[b](25,890,475)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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46	TOTAL	(3,992,840)	(1,478,005)	(5,115,547)	8,395,753

FOOTNOTE DATA

(a) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

		Q1 2022	Q2 2022	Q3 2022	Q4 2022	YTD 2022
EIM Purchases	$	2,171,091	$ 5,014,918	$ 7,307,567	$ 33,842,159	$ 48,335,735
Intertie Purchases		18,705	117,995	1,124,603	444,069	1,705,372
Total by Quarter	**$**	**2,189,796**	**$ 5,132,913**	**$ 8,432,170**	**$ 34,286,228**	**$ 50,041,107**

(b) Concept: IsoOrRtoSettlementsEnergyNetSales

		Q1 2022	Q2 2022	Q3 2022	Q4 2022	YTD 2021
EIM Purchases	$	(6,154,267)	$ (5,895,731)	$ (12,246,143)	$ (23,857,420)	$ (48,153,561)
Intertie Purchases		(28,369)	(715,187)	(1,301,574)	(2,033,055)	$ (4,078,185)
Total by Quarter	**$**	**(6,182,636)**	**$ (6,610,918)**	**$ (13,547,717)**	**$ (25,890,475)**	**$ (52,231,746)**

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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]92,572	MW	8,348,294
2	Reactive Supply and Voltage	[c]0			[d]24,660	MW	158,159
3	Regulation and Frequency Response	7,622	MWH	624	[e]6,252	MW	2,262,417
4	Energy Imbalance	(13,707)	MWH	(899,772)	(46,992)	MWH	(2,349,310)
5	Operating Reserve - Spinning	2,604,211	MWH	753,077	[f]7,691	MW	1,013,529
6	Operating Reserve - Supplement	2,604,211	MWH	498,532	[g]7,691	MW	986,160
7	Other	[h]71542	MW	2,418,030	[i]64,056	MWH	(3,167,913)
8	Total (Lines 1 thru 7)	5,273,879		2,770,491	155,930		7,251,336

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits

Number of Units	Unit of measure	Dollars
139,077	MW	$ 25,707,894
793	MWh	719
		$ 25,708,613

(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
71,805	MW	$ 77,004
793	MWh	—
		$ 77,004

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: 4,922 MW, Dollars: $557,541Schedule 13, Units: 1,329 MW, Dollars: $1,704,876Units 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: 04/14/2023	Year/Period of Report End of: 2022/ 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	4,923	1	18	[y]4,013	[ak]312	581	17	4,080	[aw]303
2	February	5,091	23	8	[z]4,126	[al]368	581	16	3,785	[ax]388
3	March	4,682	10	8	[aa]3,743	[am]341	581	17	598	[ay]234
4	Total for Quarter 1				11,882	1,021	1,743	50	8,463	925
5	April	4,276	13	9	[ab]3,375	[an]298	581	22	848	[az]275
6	May	3,795	13	8	[ac]2,917	[ao]286	581	11	1,418	[ba]263
7	June	4,242	27	18	[ad]3,346	[ap]315	581	0	2,697	[bb]272
8	Total for Quarter 2				9,638	899	1,743	33	4,963	810
9	July	4,562	28	18	[ae]3,651	[aq]329	581	1	2,920	[bc]234
10	August	4,328	8	18	[af]3,423	[ar]322	581	2	3,210	[bd]320
11	September	3,807	1	18	[ag]2,907	[as]306	581	13	911	[be]180
12	Total for Quarter 3				9,981	957	1,743	16	7,041	734
13	October	3,890	25	19	[ah]2,976	[at]319	581	14	750	[bf]240
14	November	4,940	29	18	[ai]3,984	[au]357	581	18	2,821	[bg]155
15	December	5,619	22	18	[aj]4,728	[av]289	581	21	4,341	[bh]182
16	Total for Quarter 4				11,688	965	1,743	53	7,912	577
17	Total				43,189	3,842	6,972	152	28,379	3,046
	NAME OF SYSTEM: 2) Southern Intertie (Page 400)									
1	January	[a]700			0	0	400	300	0	0
2	February	[b]700			0	0	400	300	0	0
3	March	[c]700			0	0	400	300	0	0
4	Total for Quarter 1				0	0	1,200	900	0	0
5	April	[d]700	30		0	0	400	300	6	0

6	May	(e)700			0	0	400	300	0	0
7	June	(f)700			0	0	400	300	0	0
8	Total for Quarter 2				0	0	1,200	900	6	0
9	July	(g)700			0	0	400	300	0	0
10	August	(h)700			0	0	400	300	6	0
11	September	(i)700			0	0	400	300	12	0
12	Total for Quarter 3				0	0	1,200	900	18	0
13	October	(j)700			0	0	400	300	6	0
14	November	(k)700			0	0	400	300	6	0
15	December	(l)700			0	0	400	300	6	0
16	Total for Quarter 4				0	0	1,200	900	18	0
17	Total				0	0	4,800	3,600	42	0
	NAME OF SYSTEM: 3) Colstrip (Page 400)									
1	January	(m)383			0	0	383	0	0	0
2	February	(n)383			0	0	383	0	0	0
3	March	(o)383			0	0	383	0	0	0
4	Total for Quarter 1				0	0	1,149	0	0	0
5	April	(p)383			0	0	383	0	0	0
6	May	(q)383			0	0	383	0	0	0
7	June	(r)383			0	0	383	0	0	0
8	Total for Quarter 2				0	0	1,149	0	0	0
9	July	(s)383			0	0	383	0	0	0
10	August	(t)383			0	0	383	0	0	0
11	September	(u)383			0	0	383	0	0	0
12	Total for Quarter 3				0	0	1,149	0	0	0
13	October	(v)383			0	0	383	0	0	0
14	November	(w)383			0	0	383	0	0	0
15	December	(x)713			0	0	713	0	0	0
16	Total for Quarter 4				0	0	1,479	0	0	0
17	Total				0	0	4,926	0	0	0
	NAME OF SYSTEM: Total (Page 400)									
1	January	6,006			4,013	312	1,364	317	4,080	303
2	February	6,174			4,126	368	1,364	316	3,785	388
3	March	5,765			3,743	341	1,364	317	598	234
4	Total for Quarter 1				11,882	1,021	4,092	950	8,463	925
5	April	5,359			3,375	298	1,364	322	854	275
6	May	4,878			2,917	286	1,364	311	1,418	263
7	June	5,325			3,346	315	1,364	300	2,697	272
8	Total for Quarter 2				9,638	899	4,092	933	4,969	810
9	July	5,645			3,651	329	1,364	301	2,920	234
10	August	5,411			3,423	322	1,364	302	3,216	320
11	September	4,890			2,907	306	1,364	313	923	180
12	Total for Quarter 3				9,981	957	4,092	916	7,059	734
13	October	4,973			2,976	319	1,364	314	756	240
14	November	6,023			3,984	357	1,364	318	2,827	155
15	December	7,032			4,728	289	1,694	321	4,347	182
16	Total for Quarter 4				11,688	965	4,422	953	7,930	577
17	Total				43,189	3,842	16,698	3,752	28,421	3,046

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(b) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(c) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(d) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(e) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(f) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(g) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(h) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(i) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(j) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(k) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(l) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(m) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(n) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(o) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(p) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(q) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(r) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(s) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(t) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(u) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(v) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(w) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(x) Concept: MonthlyPeakLoadExcludingIsoAndRto

Day and Hour of Monthly Peak in columns (c) and (d) were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

(y) 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.

(z) 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.

(aa) 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.

(ab) 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.

(ac) 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.

(ad) 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.

(ae) 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.

(af) 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.

(ag) 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.

(ah) 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.

(ai) 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.

(aj) 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.

(ak) Concept: FirmNetworkServiceForOther

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.

(al) Concept: FirmNetworkServiceForOther

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.

(am) Concept: FirmNetworkServiceForOther

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.

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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.

(ao) Concept: FirmNetworkServiceForOther

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.

(ap) Concept: FirmNetworkServiceForOther

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.

(aq) Concept: FirmNetworkServiceForOther

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.

(ar) Concept: FirmNetworkServiceForOther

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.

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(at) Concept: FirmNetworkServiceForOther

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.

(au) Concept: FirmNetworkServiceForOther

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.

(av) Concept: FirmNetworkServiceForOther

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.

(aw) 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.

(ax) 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.

(ay) 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.

(az) 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.

(ba) 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.

(bb) 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.

(bc) 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.

(bd) 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.

(be) 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.

(bf) 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.

(bg) 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.

(bh) 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: 04/14/2023	Year/Period of Report End of: 2022/ 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: 2023-04-14	Year/Period of Report End of: 2022/ 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)	21,613,415
3	Steam	4,464,059	23	Requirements Sales for Resale (See instruction 4, page 311.)	7,136
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,037,297
5	Hydro-Conventional	758,615	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	22,721
7	Other	5,976,262	27	Total Energy Losses	1,343,941
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	11,198,936	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	29,024,510
10	Purchases (other than for Energy Storage)	17,932,254			
10.1	Purchases for Energy Storage				
11	Power Exchanges:				
12	Received	484,951			
13	Delivered	591,631			
14	Net Exchanges (Line 12 minus line 13)	(106,680)			
15	Transmission For Other (Wheeling)				
16	Received	8,890,062			
17	Delivered	8,890,062			
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)	29,024,510			

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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)]2,630,445	264,405	4,187	5	18
30	February	2,326,176	287,826	4,323	23	8
31	March	2,366,313	344,834	3,910	10	8
32	April	2,089,254	231,960	3,503	13	9
33	May	1,977,495	267,841	3,029	13	8
34	June	1,884,102	322,025	3,478	27	18
35	July	2,342,638	572,785	3,819	28	18
36	August	2,435,868	615,774	3,597	8	18
37	September	2,394,524	822,806	3,044	1	18
38	October	2,240,575	576,340	3,071	25	19
39	November	2,873,884	720,085	4,114	29	18
40	December	3,073,120	619,900	4,807	22	18
41	Total	28,634,394	5,646,581			

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	2,579		5.5	1	1100
2	February	2,100		5.1	23	0800
3	March	1,931		3.9	10	0800
4	**Total**	**6,610**	**0**			
5	April	1,665		3.8	16	0800
6	May	1,380		3.0	8	0900
7	June	1,062		2.2	19	0900
8	**Total**	**4,107**	**0**			
9	July	1,191		2.6	3	1100
10	August	1,165		2.2	1	1000
11	September	1,048		2.2	3	1800
12	**Total**	**3,404**	**0**			
13	October	1,287		2.7	23	0900
14	November	2,267		5.2	29	1800
15	December	3,087		7.1	22	0900
16	**Total**	**6,641**	**0**			
17	**Yr Total**	**20,762**	**0**			

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 Mct.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
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	Plant Name: Lower Snake River	Plant Name: Mint Farm	Plant Name: Sumas	W
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	Wind Turbine	Combined Cycle	Combined Cycle	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor	Outdoor	Outdoor	Outdoor	Outdoor	Outdoor	Outdoor	Outdoor	Outdoor	Outdoor	Outdoor	Outdoor	
3	Year Originally Constructed	1984	1993	1994	1981	2002	1984	2001	2004	2005	2012	2007	1993	
4	Year Last Unit was Installed	1986	1993	1994	1981	2002	1984	2001	2004	2008	2012	2007	1993	
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	343.0	320.0	127.0	
6	Net Peak Demand on Plant - MW (60 minutes)	369.9	164.8	274.9	149.0	134.9	206.8	107.0	313.2	152.1	338.1	328.2	130.3	
7	Plant Hours Connected to Load	8,760	3,409	4,346	639	4,912	1,687	1,005	5,861	8,654	7,891	6,018	4,110	
8	Net Continuous Plant Capability (Megawatts)	0	0	0	0	0	0	0	0	0	0	0	0	
9	When Not Limited by Condenser Water	370	165	253	149	136	0	0	315	0	0	0	0	
10	When Limited by Condenser Water	0	0	0	0	0	0	0	0	0	0	0	0	
11	Average Number of Employees	[g]0	16	[h]0	6	[i]0	5	4	17	6	5	17	13	
12	Net Generation, Exclusive of Plant Use - kWh	2,726,665,000	426,765,000	983,279,413	49,663,790	627,630,945	216,228,100	57,030,800	1,591,661,000	350,737,856	770,633,550	1,605,295,500	458,958,000	11
13	Cost of Plant: Land and Land Rights	2,788,745	1,051,000	0	785,528	699,814	1,502,988	0	1,288,140	0	203,682	1,194,000	795,165	
14	Structures and Improvements	129,794,061	10,037,202	6,594,636	3,194,161	6,213,352	4,064,751	1,610,745	37,212,366	3,351,299	31,393,624	12,026,050	5,697,005	2
15	Equipment Costs	401,475,568	154,991,953	118,050,997	38,651,431	62,058,281	81,313,523	64,741,339	301,714,170	168,772,630	653,022,525	114,119,499	84,333,905	37
16	Asset Retirement Costs	0	0	1,030,922	0	443,797	0	0	0	12,455,466	17,350,201	0	0	
17	Total cost (total 13 thru 20)	534,058,374	166,080,155	125,676,556	42,631,120	69,415,244	86,881,262	66,352,084	340,214,676	184,579,395	701,970,032	127,339,549	90,826,075	40

18	Cost per KW of Installed Capacity (line 17/5) Including	1,443	1,007	497	286	510	420	620	1,080	1,176	2,047	398	715	
19	Production Expenses: Oper, Supv, & Engr	83,435	347,453	752,570	36,272	2,021,111	417,860	41,869	611,387	496,218	537,997	579,942	485,205	
20	Fuel	57,889,027	24,313,557	50,925,991	3,732,243	25,810,198	15,067,273	4,318,313	66,460,717	0	0	75,771,188	22,155,250	1
21	Coolants and Water (Nuclear Plants Only)	0	0	0	0	0	0	0	0	0	0	0	0	
22	Steam Expenses	3,113,427	74,379	1,024,758	0	23,803	0	0	1,425,842	0	0	223,836	217,562	
23	Steam From Other Sources	0	0	0	0	0	0	0	0	0	0	0	0	
24	Steam Transferred (Cr)	0	0	0	0	0	0	0	0	0	0	0	0	
25	Electric Expenses	(9,914)	3,080,146	2,749,939	658,879	933,640	1,727,395	3,013	2,893,047	618,957	802,335	2,786,543	2,540,508	
26	Misc Steam (or Nuclear) Power Expenses	7,529,428	0	0	0	13,106	0	0	0	0	0	0	0	
27	Rents	0	0	0	0	0	0	0	0	829,546	3,769,260	0	0	
28	Allowances	0	0	0	0	0	0	0	0	0	0	0	0	
29	Maintenance Supervision and Engineering	883,073	8,331	0	8,331	216,396	8,331	8,331	8,331	101,650	50,611	8,331	10,673	
30	Maintenance of Structures	1,334,297	49,486	3,960	39,760	29,095	46,186	0	101,260	19,837	61,673	402,252	62,570	
31	Maintenance of Boiler (or reactor) Plant	7,604,051	487,935	587,734	0	369,848	0	0	206,367	0	0	527,336	311,984	
32	Maintenance of Electric Plant	1,867,913	1,804,923	2,040,940	723,429	916,096	2,529,082	187,500	2,297,085	4,584,940	8,265,076	2,723,551	900,283	
33	Maintenance of Misc Steam (or Nuclear) Plant	755,164	29,844	412,611	0	9,338	0	0	272,193	0	0	103,383	5,524	
34	Total Production Expenses	81,049,901	30,196,054	58,498,503	5,198,914	30,342,631	19,796,127	4,559,026	74,276,229	6,651,148	13,486,952	83,126,362	26,689,559	2
35	Expenses per Net kWh	0.0297	0.0708	0.0595	0.1047	0.0483	0.0916	0.0799	0.0467	0.0190	0.0175	0.0518	0.0582	

35	**Plant Name**	Colstrip 3 & 4	Encogen	Encogen	Ferndale	Ferndale	Frederickson	Frederickson	Frederickson 1	Fredonia 1&2	Fredonia 1&2	Fredonia 3&4	Fredonia 3&4	Goldendale	Mint Farm	S
36	Fuel Kind	Coal	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Gas	Oil	Gas	Oil	Gas	Gas	G
37	Fuel Unit	T	Mcf	bbl	Mcf	bbl	Mcf	bbl	Mcf	Mcf	bbl	Mcf	bbl	Mcf	Mcf	M
38	Quantity (Units) of Fuel Burned	1,694,897	3,468,392	1	7,475,230	14,459	588,854	3,381	4,109,779	2,451,450	5,157	505,616	380	10,068,107	10,940,089	3
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8,597	1,098,104	136,804	1,098,104	138,684	1,098,104	139,427	1,098,104	1,098,104	137,025	1,098,104	137,025	1,098,104	1,098,104	1,
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	32.430	7.010	0.000	6.589	140.195	5.782	147.049	6.280	5.908	150.512	8.457	150.512	6.601	6.926	
41	Average Cost of Fuel per Unit Burned	34.155	7.010	23.464	6.589	115.780	5.782	96.787	6.280	5.908	113.307	8.457	111.563	6.601	6.926	
42	Average Cost of Fuel Burned per Million BTU	1.986	6.384	4.084	6.000	19.877	5.266	16.528	5.719	5.380	19.688	7.701	19.385	6.011	6.307	
43	Average Cost of Fuel Burned per kWh Net Gen	0.021	0.057	0.007	0.051	0.158	0.071	0.180	0.041	0.068	0.226	0.075	0.224	0.042	0.047	

44	Average BTU per kWh Net Generation	10,687.803	8,924.551	1,709.366	8,439.221	7,938.345	13,515.338	10,876.575	7,190.474	12,600.501	11,458.249	9,767.848	11,549.174	6,946.093	7,483.577	8,

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 is 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: 04/14/2023	Year/Period of Report End of: 2022/ 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)	103	42	105
7	Plant Hours Connect to Load	8,753	8,584	5,866
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]20	19	[b]19
12	Net Generation, Exclusive of Plant Use - kWh	317,498,400	173,023,740	268,093,200
13	**Cost of Plant**			
14	Land and Land Rights	8,732,638	554,102	2,001,428
15	Structures and Improvements	46,298,923	116,213,959	16,754,414
16	Reservoirs, Dams, and Waterways	124,105,246	115,733,202	125,639,177
17	Equipment Costs	67,544,292	107,713,614	36,630,883
18	Roads, Railroads, and Bridges	1,588,316	808,565	2,648,182
19	Asset Retirement Costs			
20	Total cost (total 13 thru 20)	248,269,416	341,023,442	183,674,084
21	Cost per KW of Installed Capacity (line 20 / 5)	2,364.4706	6,315.2489	1,766.0970
22	**Production Expenses**			
23	Operation Supervision and Engineering	785,983	204,217	848,498
24	Water for Power			
25	Hydraulic Expenses	1,369,356	334,574	1,789,396
26	Electric Expenses		278,163	
27	Misc Hydraulic Power Generation Expenses	116,569	770,825	681,793
28	Rents			
29	Maintenance Supervision and Engineering	20,591	20,597	20,591
30	Maintenance of Structures	88,777	172,236	55,870
31	Maintenance of Reservoirs, Dams, and Waterways	40,260	258,440	216,332
32	Maintenance of Electric Plant	139,992	851,725	206,904
33	Maintenance of Misc Hydraulic Plant	2,179,252	121,768	1,091,632
34	Total Production Expenses (total 23 thru 33)	4,740,780	3,012,545	4,911,016
35	Expenses per net kWh	0.0149	0.0174	0.0183

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: PlantAverageNumberOfEmployees
There was a total of 39 fulltime equivalent employees at Baker. They work at both Upper Baker and Lower Baker so split the total number between the two, 20 for Lower Baker, and 19 for Upper Baker.
(b) Concept: PlantAverageNumberOfEmployees
There was a total of 39 fulltime equivalent employees at Baker. They work at both Upper Baker and Lower Baker so split the total number between the two, 20 for Lower Baker, and 19 for Upper Baker.

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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)	Generation Type (m)
1	INTERNAL COMBUSTION												
2	Crystal Mountain	1969	2.75	2.7	[a]820,570	2,866,650	1,042,418	86,657	261,725	15,473	Diesel	2,851	Internal Combustion

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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: 04/14/2023	Year/Period of Report End of: 2022/ 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 generator's own load
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 how the cost 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, generators, switching ar 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)	Other Costs Associate with Self Generate Power (Dollars (o)
1															
2															
3															
4															
5															
6															
7															
8															
9															
10															
11															
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34															

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 g 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 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 re 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 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 expens 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 tw 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 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 a 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, a 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	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPREC TAXES		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Ren
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	[a] 3rd Ac Trans Line		500.00	500.00											
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									1,765,339	116,761,590	118,526,929			
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	Wanapum	Wind Ridge	230.00	230.00	RHES-MOD,PSET	21.11		1	2-1272 ACSR						
40	Wild Horse	Poison Spring	230.00	230.00	HF2	4.52		1	1272 ACSR						
41	White River	Alderton #5	230.00	230.00	SCST, DCST	8.34		1	1590 ACCS						
42	[(j)] 230 KV Tot									13,781,481	234,171,662	247,953,143			
43	115 KV Tot					1,671.39				38,090,830	506,213,262	544,304,092			
44	55 KV Tot					77.47				266,423	21,237,318	21,503,741			
45	[(k)] ARC as per FAS 143										3,234,299	3,234,299			
36	TOTAL					2,613		40		53,904,073	881,618,131	935,522,204	15,891,756	9,838,707	398,6

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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: 04/14/2023	Year/Period of Report End of: 2022/ 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)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	N/A																
44	TOTAL		0		0	0	0										

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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: 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)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
1	ALDERTON PIERCE	Transmission		230.00	115.00	13.20	325	1	0	Static Capacitor	1	21
2	BERRYDALE SOUTH KING	Transmission		230.00	115.00	13.20	325	1	0	Static Capacitor	1	42
3	BPA BELLINGHAM	Transmission		230.00	115.00	13.20	325	1	0		0	0
4	CASCADE KITTITAS A	Transmission		230.00	115.00	34.50	50	1	0		0	0
5	CASCADE KITTITAS B	Transmission		230.00	34.50	0.00	50	1	0		0	0
6	DODGE JUNCTION GARFIELD	Transmission		230.00	34.50	0.00	200	1	0	Reactor	1	10
7	FREDONIA SKAGIT	Transmission		230.00	13.20	0.00	210	2	0		0	0
8	GOLDENDALE GOLDENDALE	Transmission		230.00	18.00	13.80	365	1	0		0	0
9	MARCH POINT SKAGIT	Transmission		230.00	115.00	13.20	325	1	0	Static Capacitor	1	23
10	NOVELTY HILL NORTH KING	Transmission		230.00	115.00	13.20	325	1	0	Static Capacitor	1	42
11	O'BRIEN SOUTH KING	Transmission		230.00	115.00	13.20	650	2	1	Static Capacitor	1	42
12	MINT FARM LONGVIEW A	Transmission		230.00	18.00	0.00	215	1	0		0	0
13	MINT FARM LONGVIEW B	Transmission		230.00	13.80	0.00	160	1	0		0	0
14	PHALEN GULCH GARFIELD	Transmission		230.00	34.50	0.00	200	1	0	Reactor	1	10
15	PORTAL WAY WHATCOM	Transmission		230.00	115.00	13.20	325	1	0		0	0
16	RICHARDS CREEK	Transmission		230.00	115.00		325	1	0		0	0
17	SAMMAMISH NORTH KING	Transmission		230.00	115.00	13.20	650	2	1	Static Capacitor	2	84
18	SEDRO WOOLLEY SKAGIT	Transmission		230.00	115.00	13.20	650	2	0	Static Capacitor	2	42
19	SOUTH BREMERTON SOUTH PENNISULA	Transmission		230.00	115.00	13.20	325	1	0		0	0
20	ST CLAIR THURSTON	Transmission		230.00	115.00	13.20	325	1	0	Static Capacitor	1	42
21	TALBOT HILL CENTRAL KING	Transmission		230.00	115.00	13.20	650	2	0	Static Capacitor	1	42
22	TONO THURSTON	Transmission		525.00	115.00	13.20	533	3	0		0	0
23	WHITE RIVER TRANSM. EAST PIERCE	Transmission		230.00	115.00	13.20	650	2	0	Static Capacitor	1	45
24	WILD HORSE WIND FARM STATION KITTITAS	Transmission		230.00	34.50	0.00	390	3	0	Static Capacitor	8	106
25	[a] WIND RIDGE KITTITAS	Transmission		230.00	115.00	13.20	325	1	0	Reactor	1	45
26	AIRPORT THURSTON	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	4
27	ALGER SKAGIT	Distribution		115.00	12.50	0.00	9	1	0		0	0
28	[b] ALPAC SOUTH KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	6
29	ANACORTES SKAGIT	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
30	[c] ARCO NORTH FERNDALE	Distribution		115.00	12.50	0.00	80	2	0	Static Capacitor	1	24
31	[d] ARCO SOUTH FERNDALE	Distribution		115.00	12.50	0.00	80	2	0	Static Capacitor	1	24

32	[e] ARCO CENTRAL FERNDALE	Distribution		115.00	12.50	0.00	80	2	0		0	0
33	ARDMORE REDMOND	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	10
34	ASBURY SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
35	AVONDALE REDMOND	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
36	BAKER RIVER LOWER SKAGIT	Distribution		115.00	13.80	0.00	133	2	0		0	0
37	BAKER RIVER SW. SKAGIT A	Distribution		115.00	34.50	0.00	25	1	0		0	0
38	BAKER RIVER SW. SKAGIT B	Distribution		34.50	12.50	0.00	8	1	0		0	0
39	BAKER RIVER UPPER SKAGIT A	Distribution		115.00	13.80	0.00	120	3	0		0	0
40	BAKER RIVER UPPER SKAGIT B	Distribution		12.50	2.40	0.00	3	3	0		0	0
41	BAKERVIEW WHATCOM	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
42	BARNES LAKE THURSTON	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
43	BELLIS WHATCOM	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
44	BELMORE SOUTH WEST KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	9
45	BERTHUSEN WHATCOM	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
46	BIG ROCK SKAGIT	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
47	BIRCH BAY WHATCOM	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	2
48	BLACKBURN	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
49	BLACK DIAMOND SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	2
50	BLAINE WHATCOM	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
51	BLUMAER THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
52	BONNEY LAKE EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
53	BOW LAKE SOUTH WEST KING	Distribution		115.00	12.50	0.00	75	3	0	Static Capacitor	1	5
54	BREMERTON SOUTH PENNISULA	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	10
55	BRIDLE TRAILS CENTRAL KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	11
56	[f] BRIGHTWATER IPS NORTH KING	Distribution		115.00	4.00	0.00	13	1	0		0	0
57	BRITTON WHATCOM	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
58	BROOKS HILL ISLAND	Distribution		115.00	12.50	0.00	20	1	0		0	0
59	BUCKLEY EAST PIERCE	Distribution		55.00	12.50	0.00	19	2	0	Static Capacitor	1	2
60	BUCKLIN HILL NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0		0	0
61	BURLINGTON SKAGIT	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
62	BURROWS BAY SKAGIT	Distribution		115.00	12.50	0.00	25	1	0		0	0
63	CAMBRIDGE SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
64	[g] CAPITOL THURSTON	Distribution		115.00	12.50	0.00	50	2	0		0	0
65	CAROLINA WHATCOM	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
66	CASCADE NORTH KING	Distribution		34.50	12.50		10	0	1		0	0
67	CEDARHURST EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
68	CENTER CENTRAL KING A	Distribution		115.00	13.09	0.00	40	1	0	Static Capacitor	1	6
69	CENTER CENTRAL KING B	Distribution		115.00	13.09	0.00	25	1	0	Static Capacitor	1	6
70	CENTRAL KITSAP NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	2
71	CHAMBERS THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	10

72	CHICO SOUTH PENNISULA A	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
73	CHICO SOUTH PENNISULA B	Distribution		34.50	12.50	0.00	16	2	0		0	0
74	CHRISTENSENS CORNER NORTH PENNISULA	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
75	CHRISTOPHER AUBURN	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
76	CLAY CREEK SOUTH EAST KING	Distribution		55.00	7.20	0.00	1	1	1		0	0
77	CLE ELUM KITTITAS	Distribution		115.00	34.50	0.00	50	1	0		0	0
78	[h] CLOVER VALLEY ISLAND	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
79	CLYDE HILL CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
80	CLYMER KITTITAS	Distribution		115.00	12.50	0.00	12	1	0		0	0
81	COLLEGE CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
82	COTTAGE BROOK NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
83	COUPEVILLE ISLAND	Distribution		115.00	12.50	0.00	20	1	0		0	0
84	CRESCENT HARBOR ISLAND	Distribution		115.00	13.00	0.00	25	1	0	Static Capacitor	1	5
85	CRESTWOOD NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
86	CRYSTAL MOUNTAIN GEN. SE KING A	Distribution		34.50	12.50	0.00	8	1	0	Static Capacitor	0	0
87	CRYSTAL MOUNTAIN GEN. SE KING B	Distribution		12.50	4.16	0.00	4	1	0		0	0
88	CUMBERLAND SE KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	3
89	CUSTER WHATCOM	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
90	DECATUR THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	2
91	DES MOINES SOUTH WEST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
92	DIERINGER EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0		0	0
93	[i] DUPONT EAST PIERCE	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
94	DUVALL NORTH KING	Distribution		115.00	12.50	0.00	25	1	0		0	0
95	EARLINGTON SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	2	6
96	EAST PORT ORCHARD SOUTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
97	EAST VALLEY SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
98	EASTGATE CENTRAL KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	1	5
99	EASTON KITTITAS	Distribution		115.00	12.50	0.00	20	1	0		0	0
100	EDGEWOOD EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	2
101	ELD INLET THURSTON	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	2
102	ELECTRON GEN. EAST PIERCE	Distribution		115.00	2.40	0.00	25	1	0		0	0
103	ELECTRON HEIGHTS EAST PIERCE A	Distribution		55.00	12.50	0.00	2	1	0		0	0
104	ELECTRON HEIGHTS EAST PIERCE B	Distribution		115.00	55.00	0.00	40	3	0		0	0
105	ELECTRON HEIGHTS EAST PIERCE C	Distribution		55.00	2.40	0.00	3	2	0		0	0
106	ELLINGSON SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	4
107	ENCOGEN GEN. WHATCOM A	Distribution		115.00	13.80	0.00	150	3	0		0	0
108	ENCOGEN GEN. WHATCOM B	Distribution		115.00	13.80	0.00	68	1	0		0	0
109	ENUMCLAW SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	2
110	EVERGREEN NORTH KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	10
111	FABER ISLAND	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	4

112	FACTORIA CENTER KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	10
113	FAIRCHILD EAST PIERCE	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	1	5
114	FAIRWOOD CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	3
115	FALCON SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
116	FALL CITY EAST KING	Distribution		115.00	12.50	0.00	25	1	0		0	0
117	FERNWOOD SOUTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
118	FOSS CORNER	Distribution		115.00	0.00	0.00	0	0	0	Static Capacitor	1	23
119	FOUR CORNERS SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
120	FRAGARIA SOUTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	2
121	FREDERICKSON GEN STATION E PIERCE A	Distribution		115.00	13.20	0.00	170	2	0		0	0
122	FREDERICKSON GEN STATION E PIERCE B	Distribution		12.50	4.20	0.00	2	2	0		0	0
123	FREDERICKSON GEN STATION E PIERCE C	Distribution		12.50	0.00	0.00	3	2	0		0	0
124	FREDERICKSON GEN STATION E PIERCE D	Distribution		115.00	6.60	0.00	0	0	0	Spare GSU	0	0
125	FREDONIA SKAGIT A	Distribution		115.00	13.20	0.00	110	2	0		0	0
126	FREDONIA SKAGIT B	Distribution		115.00	12.50	13.20	0	0	0	Spare GSU	0	0
127	FREELAND ISLAND	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
128	FREEWAY SOUTH WEST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
129	FRIENDLY GROVE THURSTON	Distribution		115.00	13.09	0.00	25	1	0	Static Capacitor	1	5
130	FRUITLAND EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
131	GAGES SKAGIT	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
132	GARDELLA EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
133	GLACIER WHATCOM	Distribution		55.00	12.50	0.00	5	1	0		0	0
134	GLENCARIN SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
135	GOODES CORNER EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
136	GRADY SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
137	GRAVELLY LAKE EAST PIERCE	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
138	GREENBANK ISLAND	Distribution		115.00	12.50	0.00	9	1	0		0	0
139	GREENWATER SOUTH EAST KING A	Distribution		55.00	13.90	0.00	20	1	0	Static Capacitor	1	5
140	GREENWATER SOUTH EAST KING B	Distribution		34.50	12.50	0.00	8	1	0		0	0
141	GRIFFIN THURSTON	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
142	HAMILTON SKAGIT	Distribution		115.00	12.50	0.00	20	1	0		0	0
143	HANNEGAN WHATCOM	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	2
144	HAPPY VALLEY WHATCOM	Distribution		115.00	12.50	0.00	25	1	0		0	0
145	HARVEST SOUTH KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	1	5
146	HAWKS PRAIRIE THURSTON	Distribution		115.00	13.09	0.00	25	1	0	Static Capacitor	1	2
147	HAZELWOOD CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	3
148	HEMLOCK EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
149	HICKOX SKAGIT	Distribution		115.00	12.50	0.00	25	1	0		0	0
150	HIGHLANDS CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5

151	HILLCREST ISLAND	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
152	HOBART SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	2
153	HOLDEN EAST PIERCE	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	2
154	HOLLYWOOD NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
155	HOPKINS RIDGE WIND FARM Columbia Cnty	Distribution		115.00	34.50	0.00	167	2	0	Static Capacitor	2	29
156	HOUGHTON NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
157	HYAK EAST KING	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
158	INGLEWOOD NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
159	JOHNSON HILL THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
160	JUANITA NORTH KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	10
161	KAPOWSIN EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
162	KENDALL WHATCOM	Distribution		115.00	12.50	55.00	30	1	1	Static Capacitor	1	2
163	KENILWORTH NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
164	KENMORE NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
165	KENT SOUTH KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	8
166	KINGSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
167	KITTITAS	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
168	KITTS CORNER SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
169	KLAHANIE EAST KING	Distribution		230.00	12.50	0.00	25	1	1	Static Capacitor	1	5
170	KNOBLE EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
171	KRAIN CORNER SOUTH EAST KING	Distribution		115.00	55.00	0.00	40	1	3		0	0
172	LABOUNTY WHATCOM	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
173	LACEY THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	4
174	LAKE HILLS CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
175	LAKE LEOTA NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
176	LAKE LOUISE WHATCOM	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
177	LAKE MCDONALD EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
178	LAKE MERIDIAN SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0		0	0
179	LAKE TAPPS EAST PIERCE	Distribution		55.00	12.50	0.00	25	1	0	Static Capacitor	1	2
180	LAKE WILDERNESS SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
181	LAKE YOUNGS SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
182	LAKOTA SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
183	LANGLEY ISLAND	Distribution		115.00	12.50	0.00	20	1	0		0	0
184	LAUREL WHATCOM	Distribution		115.00	13.09	0.00	25	1	0	Static Capacitor	1	5
185	LEA HILL SOUTHEAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	3
186	LIQUID AIR SOUTH KING	Distribution		115.00	4.20	0.00	20	2	0		0	0
187	LOCHLEVEN CENTRAL KING	Distribution		115.00	13.09	0.00	50	2	0	Static Capacitor	2	12
188	LONG LAKE SOUTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	2	10

189	LONGMIRE THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
190	LUHR BEACH THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
191	LYNDEN WHATCOM	Distribution		115.00	12.50	0.00	40	2	0	Static Capacitor	2	10
192	M STREET SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
193	MANCHESTER SOUTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	2
194	MANHATTAN SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
195	MAPLEWOOD CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0		0	0
196	MARCH POINT COGEN SKAGIT	Distribution		115.00	13.80	0.00	140	3	0		0	0
197	MARINE VIEW SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
198	MAXWELTON ISLAND COUNTY	Distribution		115.00	13.00	0.00	25	1	0	Static Capacitor	1	5
199	MCALLISTER SPRINGS THURSTON	Distribution		115.00	12.50	0.00	25	1	0		0	0
200	MCKENZIE WHATCOM	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
201	MCKINLEY THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
202	MCWILLIAMS NORTH PENNISULA	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	2
203	MEDINA CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0		0	0
204	MERCER ISLAND CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0		0	0
205	MERCERWOOD CENTRAL KING	Distribution		115.00	12.50	0.00	20	1	0		0	0
206	MERIDETH SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
207	MIDLAKES CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
208	MIDWAY SOUTH WEST KING	Distribution		115.00	12.50	0.00	0	0	0	Static Capacitor	1	42
209	MILLER BAY NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
210	(k) MIRRORMONT EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
211	MOBILE UNIT #2 SOUTH KING	Distribution		66.00	12.50	0.00	9	1	0		0	0
212	MOBILE UNIT #3 SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0		0	0
213	MOBILE UNIT #4 SOUTH KING	Distribution		115.00	12.50	0.00	15	1	0		0	0
214	MOBILE UNIT #5 SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0		0	0
215	MOBILE UNIT #6 SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0		0	0
216	MOTTMAN THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
217	MOUNT SI NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
218	MOUNT VERNON SKAGIT	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	2
219	MURDEN COVE NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
220	NORKIRK NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
221	NORLUM SKAGIT	Distribution		115.00	12.50	0.00	20	1	0		0	0
222	NORPAC SOUTHKING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
223	NORTH AREA	Distribution		115.00	12.50	0.00	25	0	1		0	0
224	NORTH BELLEVUE CENTRAL KING	Distribution		115.00	13.09	0.00	50	2	0	Static Capacitor	2	10
225	NORTH BEND EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
226	(l) NORTH BOTHELL NORTHKING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
227	NORTH NORMANDY SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
228	NORTHRUP CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
229	NORWAY HILL NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5

230	NUGENTS CORNER WHATCOM A	Distribution		34.50	12.50	0.00	8	1	0		0	0
231	NUGENTS CORNER WHATCOM B	Distribution		115.00	34.50	0.00	25	1	0		0	0
232	NUGENTS CORNER WHATCOM C	Distribution		12.50	12.50	0.00	5	1	0		0	0
233	OLD TOWN WHATCOM	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
234	OLYMPIA BREWERY THURSTON	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
235	(m) OLYMPIC ARCO PUMP WHATCOM	Distribution		115.00	4.20	0.00	6	1	0		0	0
236	(n) OLYMPIC AVON SKAGIT	Distribution		115.00	4.20	0.00	19	2	0		0	0
237	(o) OLYMPIC MOBIL WHATCOM	Distribution		115.00	4.20	0.00	9	1	0		0	0
238	(p) OLYMPIC RENTON SOUTH KING	Distribution		115.00	4.20	0.00	9	1	0		0	0
239	OLYMPIA SWITCH	Distribution		115.00	0.00	0.00	0	0	0	Static Capacitor	1	42
240	(q) OLYMPIC VAIL PIPELINE THURSTON	Distribution		115.00	4.20	0.00	6	1	0		0	0
241	(r) OLYMPIC BAYVIEW SKAGIT	Distribution		115.00	4.36	0.00	6	1	0		0	0
242	ORCHARD SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	4
243	ORILLIA SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
244	ORTING EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	2
245	OSCEOLA SOUTH EAST KING	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	2
246	OVERLAKE CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0		0	0
247	(s) PACCAR CENTRAL KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	10
248	(t) PADILLA BAY PIPELINE SKAGIT A	Distribution		115.00	12.50	0.00	9	1	0		0	0
249	PADILLA BAY PIPELINE SKAGIT B	Distribution		12.50	4.16	0.00	4	1	0		0	0
250	PANTHER LAKE SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
251	PATTERSON THURSTON	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
252	PEASLEY CANYON SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
253	PETHS CORNER SKAGIT	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	2
254	PHANTOM LAKE CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
255	PICKERING CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
256	PINE LAKE EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
257	PIPE LAKE SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	3
258	PLATEAU EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
259	PLEASANT GLADE THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
260	PLUM STREET THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
261	PLYMOUTH WHATCOM	Distribution		115.00	12.50	0.00	25	1	0		0	0
262	POINT ROBERTS WHATCOM	Distribution		25.00	12.50	0.00	19	2	0		0	0
263	PORT GAMBLE NORTH PENNISULA	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	4
264	PORT MADISON NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
265	POULSBO NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0		0	0
266	PRESIDENT PARK CENTRAL KING	Distribution		115.00	13.09	0.00	25	1	0	Static Capacitor	1	5
267	PRINE THURSTON A	Distribution		115.00	13.09	0.00	25	1	0	Static Capacitor	1	5
268	PRINE THURSTON B	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
269	QUARRY EAST PIERCE	Distribution		115.00	12.50	4.20	9	1	1		0	0

270	RAINIER VIEW THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
271	REDMOND NORTH KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	10
272	REDONDO SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
273	RENTON JUNCTION SOUTH KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	10
274	RHODES LAKE EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
275	RITA STREET SKAGIT	Distribution		115.00	12.50	0.00	20	1	0		0	0
276	RIVERBEND SKAGIT	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
277	ROCHESTER THURSTON	Distribution		115.00	12.50	0.00	40	2	0	Static Capacitor	1	5
278	ROCKY POINT SOUTH PENNISULA	Distribution		115.00	12.50	0.00	50	2	0		0	0
279	[v] ROEDER WHATCOM	Distribution		115.00	13.09	0.00	20	1	0	Static Capacitor	1	5
280	ROLLING HILLS SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
281	ROSE HILL CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
282	SAHALEE NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
283	SAINT CLAIR THURSTON	Distribution		0.00	0.00	0.00	0	0	0	Static Capacitor	1	40
284	[v] SAMMAMISH NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
285	SCENIC NORTH KING	Distribution		115.00	12.50	0.00	4	1	0		0	0
286	SCHUETT WHATCOM	Distribution		115.00	12.50	0.00	20	1	0		0	0
287	SEATAC SOUTH KING	Distribution		115.00	13.09	0.00	50	2	0		0	0
288	SEHOME WHATCOM	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
289	SEMIAHMOO WHATCOM	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
290	SEQUOIA SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
291	SERWOLD NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
292	SHANNON WHATCOM A	Distribution		34.50	12.50	0.00	8	1	0		0	0
293	SHANNON WHATCOM B	Distribution		115.00	34.50	0.00	25	1	0		1	5
294	SHAW EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
295	SHERIDAN NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
296	SHERWOOD SOUTH EAST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
297	SHUFFLETON YARD SOUTH KING A	Distribution		55.00	12.50	0.00	9	0	1		0	0
298	SHUFFLETON YARD SOUTH KING B	Distribution		55.00	7.20		3	0	1		0	0
299	SHUFFLETON YARD SOUTH KING C	Distribution		12.50	12.50		5	0	1		0	0
300	SHUFFLETON YARD SOUTH KING D	Distribution		12.50	4.20	0.00	8	0	1		0	0
301	SHUFFLETON YARD SOUTH KING E	Distribution		34.50	12.50		20	0	2		0	0
302	SHUFFLETON YARD SOUTH KING F	Distribution		115.00	34.50	0.00	25	0	1		0	0
303	SHUFFLETON YARD SOUTH KING G	Distribution		115.00	12.50	0.00	275	0	5		0	0
304	SHUFFLETON YARD SOUTH KING H	Distribution		115.00	12.50	0.00	13	0	1		0	0
305	SHUFFLETON YARD SOUTH KING I	Distribution		115.00	12.50		25	1	2		0	0
306	SHUFFLETON YARD SOUTH KING J	Distribution		230.00	115.00	34.50	50	0	1		0	0
307	SHUFFLETON YARD SOUTH KING K	Distribution		115.00	12.50	0.00	25	0	8		0	0
308	SHUFFLETON YARD SOUTH KING L	Distribution		12.50	12.50	0.00	5	0	1		0	0
309	SILVERDALE NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
310	SINCLAIR INLET SOUTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
311	SKYKOMISH NORTH KING	Distribution		115.00	12.50	0.00	9	1	0		0	0
312	SLATER WHATCOM	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5

313	SNOQUALMIE EAST KING	Distribution		115.00	12.50	0.00	25	1	0		0	0
314	SNOQUALMIE (BLACK CREEK GEN)	Distribution		34.50	12.50	0.00	5	1	0		0	0
315	SNOQUALMIE GEN. #1	Distribution		117.90	6.90	2.00	20	1	0		0	0
316	SNOQUALMIE GEN. #2	Distribution		117.90	7.20	0.00	53	1	0		0	0
317	SOMERSET CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
318	SOOS CREEK SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
319	SOUTH BELLEVUE CENTRAL KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
320	SOUTH KEYPORT NORTH PENNISULA	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	4
321	SOUTH KIRKLAND NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
322	SOUTH MERCER CENTRAL KING	Distribution		115.00	12.50	0.00	20	1	0		0	0
323	SOUTHWICK THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
324	SOUTHCENTER SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
325	SOUTH WHIDBEY SWITCH ISLAND	Distribution		115.00	0.00	0.00	0	0	0	Static Capacitor	2	42
326	SPANAWAY EAST PIERCE A	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
327	SPANAWAY EAST PIERCE B	Distribution		115.00	7.20				1			
328	SPIRITBROOK NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
329	SPURGEON CREEK	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
330	STARWOOD SOUTH KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	10
331	STATE STREET WHATCOM	Distribution		115.00	13.09	0.00	25	1	0	Static Capacitor	1	5
332	[w] STERLING NORTH KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	10
333	STEWART EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
334	SUMAS GEN STATION	Distribution		115.00	13.80	0.00	240	2	0		0	0
335	SUMMIT PARK SKAGIT	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	4
336	SUMNER EAST PIERCE	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
337	SUNRISE EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
338	SWANTOWN ISLAND	Distribution		115.00	12.50	0.00	20	1	0		0	0
339	SWEPTWING SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	3
340	TANGLEWILDE THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
341	[x] TEN MILE WHATCOM	Distribution		115.00	4.20	0.00	9	1	0		0	0
342	[y] TEXACO EAST SKAGIT	Distribution		115.00	13.80	0.00	50	2	0		0	0
343	[z] TEXACO WEST SKAGIT	Distribution		115.00	13.80	0.00	80	2	0		0	0
344	THORP KITTITAS	Distribution		34.50	12.50	0.00	9	1	0		0	0
345	THURSTON THURSTON	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	1	5
346	TILLICUM EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
347	TOLT NORTH KNG	Distribution		115.00	12.50	0.00	25	1	0		0	0
348	TOTEM NORTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
349	TRACYTON NORTH PENNISULA	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	2
350	UNION HILL EAST KING	Distribution		115.00	13.09	0.00	25	1	0	Static Capacitor	1	5
351	VALLEY JUNCTION	Distribution		115.00	0.00	0.00	0	0	0	Static Capacitor	1	23
352	VAN WYCK WHATCOM	Distribution		115.00	12.50	0.00	9	1	0		0	0

353	VASHON SOUTH PENNISULA	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	10
354	VICTORIA PARK SOUTH KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
355	[aa] VIKING WHATCOM	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
356	VISTA WHATCOM	Distribution		115.00	12.50	0.00	20	1	0	Static Capacitor	1	5
357	[ab] VITULLI NORTH KING	Distribution		115.00	12.50	0.00	50	2	0	Static Capacitor	2	10
358	WABASH SOUTH EAST KING	Distribution		55.00	12.50	0.00	9	1	0		0	0
359	WAYNE NORTH KING	Distribution		115.00	12.50	0.00	25	1	0		0	4
360	WEST AUBURN SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	4
361	WEST CAMPUS SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	2
362	WEST ISSAQUAH EAST KING	Distribution		115.00	13.09	0.00	25	1	0	Static Capacitor	1	5
363	WEST OLYMPIA THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	0	0
364	WHIDBEY ISLAND OAK HARBOR	Distribution		0.00	0.00	0.00	0	0	0	Static Capacitor	1	23
365	[ac] WEYERHAEUSER SW KING	Distribution		115.00	12.50	0.00	20	1	0		0	0
366	WEYERHAEUSER WHR BRANCH	Distribution		55.00	4.16	0.00	8	3	0		0	0
367	WHITEHORN WHATCOM	Distribution		115.00	13.20	0.00	170	2	0		0	0
368	WHITE RIVER TRANSM. EAST PIERCE A	Distribution		115.00	55.00	0.00	83	3	0		0	0
369	WHITE RIVER TRANSM. EAST PIERCE B	Distribution		55.00	7.20	0.00	3	3	0		0	0
370	WHITEHORN GEN WHATCOM A	Distribution		12.50	0.00	0.00	1	2	0		0	0
371	WHITEHORN GEN WHATCOM B	Distribution		12.50	0.50	0.00	2	2	0		0	0
372	WHITEHORN GEN WHATCOM C	Distribution		12.50	4.20	0.00	2	2	0		0	0
373	WILKESON EAST PIERCE	Distribution		55.00	12.50	0.00	9	1	0		0	0
374	WILSON SKAGIT	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
375	WINSLOW NORTH PENNISULA	Distribution		115.00	12.50	0.00	25	1	0		0	0
376	WOBURN WHATCOM	Distribution		115.00	12.50	0.00	25	1	0		0	0
377	WOLDALE KITTITAS	Distribution		115.00	12.50	0.00	20	1	0		0	0
378	WOODLAND EAST PIERCE	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	2
379	YELM THURSTON	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	2	26
380	ZENITH SOUTHWEST KING	Distribution		115.00	12.50	0.00	25	1	0	Static Capacitor	1	5
381	TotalDistributionSubstationMember			37,877	4,518	109	10,052	399	35		256	1,458
382	TotalTransmissionSubstationMember			6,045	2,156	246	8,873	35	2		23	596
383	Total			43,922	6,674	355	18,925	434	37		279	2,054

Name of Respondent: Puget Sound Energy, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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

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

(l) Concept: SubstationNameAndLocation

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

(m) Concept: SubstationNameAndLocation

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

(n) Concept: SubstationNameAndLocation

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

(o) Concept: SubstationNameAndLocation

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

(p) Concept: SubstationNameAndLocation

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

(q) Concept: SubstationNameAndLocation

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

(r) Concept: SubstationNameAndLocation

Olympic Pipeline leases PSE owned transformer at Olympic Bayview Substation.

(s) Concept: SubstationNameAndLocation

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

(t) Concept: SubstationNameAndLocation

Olympic Pipeline leases PSE owned transformer at Padilla Bay Substation.

(u) Concept: SubstationNameAndLocation

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

(v) Concept: SubstationNameAndLocation

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

(w) Concept: SubstationNameAndLocation

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

(x) Concept: SubstationNameAndLocation

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

(y) Concept: SubstationNameAndLocation

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

(z) Concept: SubstationNameAndLocation

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

(aa) 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.

(ab) Concept: SubstationNameAndLocation

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

(ac) 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: 04/14/2023	Year/Period of Report End of: 2022/ 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**			
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19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	General and Adminstrative Expenses	Puget Energy, Inc.	146	295,996
22	Operations and Maintenance Expenses	Puget LNG, LLC	146	1,387,665
23	General and Adminstrative Expenses	Puget Holdings, LLC	146	1,401,428
24	Operations and Maintenance Expenses	Puget Holdings, LLC	146	251,312
42				