THIS FILING IS (CHECK ONE BOX FOR EACH ITEM)			
Item 1: [X] An Initial (Original) Submission	OR	[ ]	Resubmission No. ____
Item 2: [ ] An Original Signed Form	OR	[ ]	Conformed Copy

Form Approved
OMB No. 1902-0021
(Expires 3/31/2005)

FERC Form No. 1:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

This report is mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1. 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 this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	**Year of Report**
Puget Sound Energy, Inc.	**Dec. 31,** 2002

INSTRUCTIONS FOR FILING THE FERC FORM NO. 1

GENERAL INFORMATION

I. Purpose

This form is a regulatory support requirement (18 CFR 141.1). It is designed to collect financial and operational information from major electric utilities, Licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. This report is also secondarily considered to be a nonconfidential public use form supporting a statistical publication (Financial Statistics of Selected Electric Utilities), published by the Energy Information Administration.

II. Who Must Submit

Each major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of The Federal Power Act (18 CFR 101), must submit this form.

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

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

III. What and Where to Submit

(a) Submit this form electronically through the Form 1 Submission Software and an original and six (6) conformed paper copies, properly filed in and attested, to:

Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, NE.
Room 1A
Washington, DC 20426

Retain one copy of this report for your files.

Include with the original and each conformed paper copy of this form the subscription statement required by 18 C.F.R. 385.2011(c)(5). Paragraph (c)(5) of 18 C.F.R. 385.2011 requires each respondent submitting data electronically to file a subscription stating that the paper copies contain the same information as the electronic filing, that the signer knows the contents of the paper copies and electronic filing, and that the contents as stated in the copies and electronic filing are true to the best knowledge and belief of the signer.

(b) Submit, immediately upon publication, four (4) copies of the Latest annual report to stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. (Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Page 4, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared.) Mail these reports to:

Chief Accountant
Federal Energy Regulatory Commission
888 First Street, NE.
Washington, DC 20426

(c) For the CPA certification, submit with the original submission, or within 30 days after the filing date for this form, a Letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984):

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

(ii) 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 CFR 41.10-41.12 for specific qualifications.)

III. What and Where to Submit (Continued)
(c) Continued

Schedules	Reference 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

When accompanying this form, insert the Letter or report immediately following the cover sheet. When submitting after the filing date for this form, send the letter or report to the office of the Secretary at the address indicated at III (a).

Use the following format for the Letter or report unless unusual circumstances or conditions, explained in the Letter or report, demand that it be varied . Insert parenthetical phrases only when exceptions are reported.

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

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

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

(d) Federal, State and Local Governments and other authorized users may obtain additional blank copies to meet their requirements free of charge from:

Public Reference and Files Maintenance Branch
Federal Energy Regulatory Commission
888 First Street, NE. Room 2A ES-1
Washington, DC 20426
(202) 208-2474

IV. When to Submit

Submit this report form on or before April 30th of the year following the year covered by this report.

V. Where to Send Comments on Public Reporting Burden

The public reporting burden for this collection of information is estimated to average 1,217 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. Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 888 First Street N.E., Washington, DC 20426 (Attention: Mr. Michael Miller, CI-1); 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 this collection of information does not display a valid control number. (44 U.S.C. 3512(a)).

GENERAL INSTRUCTIONS

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

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

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

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2, 3, and 4.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below). The date of the resubmission must be reported in the header for all form pages, whether or not they are changed from the previous filing.

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

VII. For any resubmissions, submit the electronic filing using the Form 1 Submission Software and an original and six (6) conformed paper copies of the entire form, as well as the appropriate number of copies of the subscription statement indicated at instruction III (a). Resubmissions must be numbered sequentially on the cover page of the paper copies of the form. In addition, the cover page of each paper copy must indicate that the filing is a resubmission. Send the resubmissions to the address indicated at instruction III (a).

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

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

DEFINITIONS

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

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

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

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

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

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

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

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

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

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

"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 form or 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 filed..."

General Penalties

"Sec. 315. (a) Any licensee or public utility which willfully fails, within the time prescribed by the Commission, to comply with any order of the Commission, to file any report required under this Act or any rule or regulation of the Commission thereunder, to submit any information of document required by the Commission in the course of an investigation conducted under this Act ... shall forfeit to the United States an amount not exceeding $1,000 to be fixed by the Commission after notice and opportunity for hearing..."

FERC FORM NO. 1:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION	
01 Exact Legal Name of Respondent Puget Sound Energy, Inc.	02 Year of Report Dec. 31, 2002
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Year *(Street, City, State, Zip Code)* P.O. Box 97034, Bellevue, WA 98009-9734	
05 Name of Contact Person James W. Eldredge	06 Title of Contact Person VP, Corp Sec & Controlr
07 Address of Contact Person *(Street, City, State, Zip Code)* P.O. Box 97034, Bellevue, WA 98009-9734	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(425) 462-3135	(1) ☒ An Original (2) ☐ A Resubmission	04/30/2003

ATTESTATION

The undersigned officer certifies that he/she has examined the accompanying report: that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
James W. Eldredge		04/30/2003
02 Title VP, Corp Secretary & Controller		

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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".

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Four copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

GENERAL INFORMATION

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

PUGET SOUND ENERGY, INC.
James W.Eldredge, Vice President, Corporate Secretary and Chief Accounting Officer
P.O. Box 97034 OBC-15
Bellevue, WA 98009-9734

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

Washington, September 12, 1960

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

Not Applicable

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

Electric - Washington
Gas - Washington

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

CONTROL OVER RESPONDENT

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

Puget Energy, Inc., an energy services holding company, holds all outstanding shares of Puget Sound Energy, Inc. common stock.

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Puget Western, Inc.	Real Estate Operations	100	
2				
3	GP Acquisition Corp.	General partner-Encogen	100	
4				
5	LP Acquisition Corp.	Limited partner-Encogen	100	
6				
7	Puget Sound Energy Services, Inc.	Energy Service Provider	100	
8				
9	PSE Utility Soltutions, Inc.	Energy Service Provider	100	
10				
11	WNG Cap 1	Financing	100	
12				
13	Washington Energy Gas Marketing	Gas Transportation	100	
14				
15	Hydro Energy Development Corporation	Small Hydro Development	100	
16	Controlled by Hydro Energy Development Co.			
17	Black Creek Hydro, Inc.	Small Hydro Development	100	
18	Baker Mountain Hydro Electric Co., Inc.	Small Hydro Development	100	
19	Cascade River Hydro, Inc.	Small Hydro Development	100	
20	Nooksack River Hydro, Inc.	Small Hydro Development	100	
21	Skagit River Hydro, Inc.	Small Hydro Development	100	
22	Skykomish River Hydro, Inc.	Small Hydro Development	100	
23	Snoqualmie River Hydro, Inc.	Small Hydro Development	100	
24	Suiattle River Hydro, Inc.	Small Hydro Development	100	
25	Washington Hydro Development Corp.	Small Hydro Development	100	
26	Calligan Hydro, Inc.	Small Hydro Development	100	
27	Warm Creek Hydro, Inc.	Small Hydro Development	100	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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.
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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	Skookum Hydro, Inc.	Small Hydro Development	100	
2	Hancock Hydro, Inc.	Small Hydro Development	100	
3	Pacific Hydro, Inc.	Small Hydro Development	100	
4	Controlled by Pacific Hydro, Inc.:			
5	Pacific Oregon Corporation	Small Hydro Development	100	
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) X An Original (2) __ A Resubmission	04/30/2003	Dec 31, 2002

FOOTNOTE DATA

Schedule Page: 103   Line No.: 18   Column: d

[redacted]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	President & Chief Executive Officer	Stephen P. Reynolds	650,000
3	Vice President, Corporate Secretary & Controller	James W. Eldredge	175,000
4	Vice President Finance & Treasurer	Donald E. Gaines	175,000
5	Vice President - Energy Supply	William A. Gaines	202,914
6	Vice President - Human Resources	Dorothy A. Graham	186,438
7	Vice President - Customer Services	Penny J. Gullekson	164,808
8	Sr Vice President -Regional Svcs & Community Affairs	Timothy J. Hogan	250,000
9	Sr Vice President Finance & C.F.O.	Stephen A. McKeon	366,684
10	Sr Vice President - Operations	Susan McLain	224,507
11	Vice President - Energy Portfolio Management	Julia M. Ryan	235,000
12	Sr Vice President & C.O.O.	Gary B. Swofford	320,000
13	Vice President - Corporate Planning	Paul M. Wiegand	164,808
14	Sr Vice President - Energy Resources	Eric M. Markell	212,500
15	Vice President -Governmental & Regulatory Relations	Kimberely J. Harris	200,000
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Schedule Page: 104   Line No.: 7   Column: b

Penny Gullekson left Puget Sound Energy in 2002. Darren P. Brady became Vice President - Customer Services in February 2003.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Douglas P. Beighle	Seattle, Washington
2	Charles W. Bingham	Tacoma, Washington
3	Phyllis J. Campbell	Seattle, Washington
4	Craig W. Cole	Bellingham, Washington
5	Robert L. Dryden	Seattle, Washington
6	Tomio Moriguchi	Seattle, Washington
7	Kenneth P. Mortimer	Bellingham, Washington
8	Sally G. Narodick	Seattle, Washington
9	Stephen P. Reynolds, President & CEO	Bellevue, Washington
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16	Note: No Executive Board Committee	
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IMPORTANT CHANGES DURING THE YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, 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.

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

1. Changes in and important additions to franchises:
Four new (replacement) franchises were granted and accepted by the company in 2002: Oak Harbor, Kitsap County, Shoreline and Pierce County. All Locations are in Washington State.
2. None
3. None
4. In 2002, PSE entered into a lease agreement with BTC Seattle, LLC, as the landlord, under which PSE leases five floors of Building B in The Summit building located in Bellevue, Washington. The lease term begins in August 2003, with moving and partial occupancy beginning in June 2003. The lease terms are for five to ten year periods, depending on individual floor, but can be canceled by PSE after three to seven years, also dependent on individual floor agreements. The lease agreement was signed June 17, 2002.
5. None
6. Short term debt on December 31, 2002 was $30.3 million, all of which was commercial paper. On December 31, 2001, short term debt was $338.2 million, which consisted of $123.2 million of commercial paper and $215.0 million of bank line of credit borrowing.
7. None
8. Employees represented by the IBEW received a 3% wage increase effective April 1, 2002. Employees represented by the UA received a 3% wage increase effective October 1, 2002. In addition exempt and non-exempt employees received an average 3% salary increase effective March 1, 2002. Overall annualized payroll costs decreased an estimeted $17.6 million in 2002, however, due to the transition of service jobs to outside service providers.
9. None
10.None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	5,955,481,829	6,142,161,302
3	Construction Work in Progress (107)	200-201	123,306,691	108,658,275
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,078,788,520	6,250,819,577
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	2,194,048,225	2,337,832,036
6	Net Utility Plant (Enter Total of line 4 less 5)		3,884,740,295	3,912,987,541
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203	0	0
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
9	Net Nuclear Fuel (Enter Total of line 7 less 8)		0	0
10	Net Utility Plant (Enter Total of lines 6 and 9)		3,884,740,295	3,912,987,541
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored Underground - Noncurrent (117)		3,241,171	3,241,171
13	**OTHER PROPERTY AND INVESTMENTS**			
14	Nonutility Property (121)	221	1,105,453	2,122,608
15	(Less) Accum. Prov. for Depr. and Amort. (122)		0	423,344
16	Investments in Associated Companies (123)		0	0
17	Investment in Subsidiary Companies (123.1)	224-225	116,975,228	124,345,549
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
19	Noncurrent Portion of Allowances	228-229	0	0
20	Other Investments (124)		33,372,539	41,526,680
21	Special Funds (125-128)		0	0
22	TOTAL Other Property and Investments (Total of lines 14-17,19-21)		151,453,220	167,571,493
23	**CURRENT AND ACCRUED ASSETS**			
24	Cash (131)		-2,959,692	62,394,975
25	Special Deposits (132-134)		215,757	217,249
26	Working Fund (135)		1,551,631	1,816,996
27	Temporary Cash Investments (136)		20,011,715	48,925,000
28	Notes Receivable (141)		316,936	335,106
29	Customer Accounts Receivable (142)		148,992,879	127,929,184
30	Other Accounts Receivable (143)		129,847,517	121,721,540
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		45,150,181	43,255,709
32	Notes Receivable from Associated Companies (145)		0	0
33	Accounts Receivable from Assoc. Companies (146)		9,421,041	1,038,287
34	Fuel Stock (151)	227	11,960,566	11,980,471
35	Fuel Stock Expenses Undistributed (152)	227	0	0
36	Residuals (Elec) and Extracted Products (153)	227	0	0
37	Plant Materials and Operating Supplies (154)	227	26,312,597	25,255,860
38	Merchandise (155)	227	0	0
39	Other Materials and Supplies (156)	227	0	0
40	Nuclear Materials Held for Sale (157)	202-203/227	0	0
41	Allowances (158.1 and 158.2)	228-229	0	0
42	(Less) Noncurrent Portion of Allowances		0	0
43	Stores Expense Undistributed (163)	227	1,357,293	1,350,654
44	Gas Stored Underground - Current (164.1)		45,111,544	24,399,930
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		576,201	576,201
46	Prepayments (165)		7,142,777	8,867,076
47	Advances for Gas (166-167)		0	0
48	Interest and Dividends Receivable (171)		203,206	705,260
49	Rents Receivable (172)		0	0
50	Accrued Utility Revenues (173)		147,008,022	112,115,106
51	Miscellaneous Current and Accrued Assets (174)		231,187	0
52	Derivative Instrument Assets (175)		0	103,376

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
53	Derivative Instrument Assets - Hedges (176)		0	13,507,223
54	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 53)		502,150,996	519,983,785
55	**DEFERRED DEBITS**			
56	Unamortized Debt Expenses (181)		22,488,513	20,825,488
57	Extraordinary Property Losses (182.1)	230	26,601,680	21,851,678
58	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
59	Other Regulatory Assets (182.3)	232	584,499,712	554,761,373
60	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
61	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)		0	0
62	Clearing Accounts (184)		0	0
63	Temporary Facilities (185)		145,972	-50,704
64	Miscellaneous Deferred Debits (186)	233	96,824,607	123,298,182
65	Def. Losses from Disposition of Utility Plt. (187)		4,645,837	3,523,361
66	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
67	Unamortized Loss on Reaquired Debt (189)		7,876,225	6,797,581
68	Accumulated Deferred Income Taxes (190)	234	112,200,706	116,074,634
69	Unrecovered Purchased Gas Costs (191)		37,228,034	-83,810,667
70	TOTAL Deferred Debits (Enter Total of lines 56 thru 69)		892,511,286	763,270,926
71	TOTAL Assets and Other Debits (Enter Total of lines 10,11,12,22,54,70)		5,434,096,968	5,367,054,916

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	859,037,900	859,037,900
3	Preferred Stock Issued (204)	250-251	110,661,900	103,161,900
4	Capital Stock Subscribed (202, 205)	252	300,000,000	300,000,000
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	478,145,250	478,145,250
7	Other Paid-In Capital (208-211)	253	-115,303,195	29,761,143
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	9,571,316	9,571,316
11	Retained Earnings (215, 215.1, 216)	118-119	32,503,911	21,330,840
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	22,841,201	45,640,133
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	1,777,193
15	TOTAL Proprietary Capital (Enter Total of lines 2 thru 13)		1,678,315,651	1,829,283,043
16	**LONG-TERM DEBT**			
17	Bonds (221)	256-257	2,170,860,000	2,093,860,000
18	(Less) Reaquired Bonds (222)	256-257	0	0
19	Advances from Associated Companies (223)	256-257	4,560,578	0
20	Other Long-Term Debt (224)	256-257	0	0
21	Unamortized Premium on Long-Term Debt (225)		0	0
22	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		45,371	27,776
23	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)		2,175,375,207	2,093,832,224
24	**OTHER NONCURRENT LIABILITIES**			
25	Obligations Under Capital Leases - Noncurrent (227)		0	0
26	Accumulated Provision for Property Insurance (228.1)		0	0
27	Accumulated Provision for Injuries and Damages (228.2)		650,000	600,000
28	Accumulated Provision for Pensions and Benefits (228.3)		0	0
29	Accumulated Miscellaneous Operating Provisions (228.4)		15,868,490	37,578,088
30	Accumulated Provision for Rate Refunds (229)		0	0
31	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 24 thru 29)		16,518,490	38,178,088
32	**CURRENT AND ACCRUED LIABILITIES**			
33	Notes Payable (231)		338,168,000	30,340,000
34	Accounts Payable (232)		168,146,964	202,382,712
35	Notes Payable to Associated Companies (233)		2,000	2,000
36	Accounts Payable to Associated Companies (234)		15,204,211	2,917,945
37	Customer Deposits (235)		8,573,828	10,625,498
38	Taxes Accrued (236)	262-263	58,180,964	61,701,956
39	Interest Accrued (237)		42,505,301	37,942,232
40	Dividends Declared (238)		1,101,252	1,102,105
41	Matured Long-Term Debt (239)		0	0
42	Matured Interest (240)		0	0
43	Tax Collections Payable (241)		-40,512	382,467
44	Miscellaneous Current and Accrued Liabilities (242)		11,475,746	12,888,152
45	Obligations Under Capital Leases-Current (243)		0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
46	Derivative Instrument Liabilities (244)		0	0
47	Derivative Instrument Liabilities - Hedges (245)		0	2,410,030
48	TOTAL Current & Accrued Liabilities (Enter Total of lines 32 thru 44)		643,317,754	362,695,097
49	**DEFERRED CREDITS**			
50	Customer Advances for Construction (252)		32,888,868	38,675,431
51	Accumulated Deferred Investment Tax Credits (255)	266-267	4,683,272	4,022,545
52	Deferred Gains from Disposition of Utility Plant (256)		17,277,076	14,421,004
53	Other Deferred Credits (253)	269	153,726,087	153,389,570
54	Other Regulatory Liabilities (254)	278	5,563,451	4,926,645
55	Unamortized Gain on Reaquired Debt (257)		1,143,736	1,020,290
56	Accumulated Deferred Income Taxes (281-283)	272-277	705,287,376	826,610,979
57	TOTAL Deferred Credits (Enter Total of lines 47 thru 53)		920,569,866	1,043,066,464
58			0	0
59			0	0
60			0	0
61			0	0
62			0	0
63			0	0
64			0	0
65			0	0
66			0	0
67			0	0
68			0	0
69			0	0
70			0	0
71	TOTAL Liab and Other Credits (Enter Total of lines 14,22,30,45,54)		5,434,096,968	5,367,054,916

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another Utility column (i, k, m, o) in a similar manner to a utility department. Spread the amount(s) over Lines 02 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7,9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
4. Use pages 122-123 for important notes regarding the statement of income or any account thereof.
5. 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 a material refund to the utility with respect to power or gas purchases. State for each year affected 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 and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	2,062,688,718	2,679,952,792
3	Operating Expenses			
4	Operation Expenses (401)	320-323	1,244,580,770	1,841,252,201
5	Maintenance Expenses (402)	320-323	68,234,741	74,573,076
6	Depreciation Expense (403)	336-337	177,294,073	169,555,400
7	Amort. & Depl. of Utility Plant (404-405)	336-337	27,689,652	25,984,085
8	Amort. of Utility Plant Acq. Adj. (406)	336-337	7,435,691	10,282,176
9	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		4,808,186	3,578,856
10	Amort. of Conversion Expenses (407)			
11	Regulatory Debits (407.3)		583,945	
12	(Less) Regulatory Credits (407.4)			
13	Taxes Other Than Income Taxes (408.1)	262-263	202,110,150	208,466,687
14	Income Taxes - Federal (409.1)	262-263	-87,153,016	47,111,312
15	- Other (409.1)	262-263		
16	Provision for Deferred Income Taxes (410.1)	234, 272-277	195,670,455	60,062,999
17	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	57,574,970	39,712,081
18	Investment Tax Credit Adj. - Net (411.4)	266	-660,727	-688,700
19	(Less) Gains from Disp. of Utility Plant (411.6)		3,272,229	705,288
20	Losses from Disp. of Utility Plant (411.7)		557,506	10,140
21	(Less) Gains from Disposition of Allowances (411.8)		351,329	344,794
22	Losses from Disposition of Allowances (411.9)			
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		1,779,952,898	2,399,426,069
24	Net Util Oper Inc (Enter Tot line 2 less 23) Carry fwd to P117,line 25		282,735,820	280,526,723

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

STATEMENT OF INCOME FOR THE YEAR (Continued)

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.
7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be included on pages 122-123.
B. Enter on pages 122-123 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 approximate dollar effect of such changes.
9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.
10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on pages.122-123 or in a footnote.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	
						1
1,365,533,215	1,864,881,617	697,155,503	815,071,175			2
						3
777,399,906	1,261,667,148	472,017,317	597,542,481	-4,836,453	-17,957,428	4
60,539,674	67,158,874	7,695,067	7,414,202			5
122,476,152	118,375,247	54,817,921	51,180,153			6
18,780,946	18,204,112	8,908,706	7,779,973			7
7,435,691	10,282,176					8
4,750,002	3,500,000	58,184	78,856			9
						10
383,633		200,312				11
						12
133,061,181	134,142,302	69,048,969	74,324,385			13
-43,578,530	40,909,612	-43,574,486	6,201,700			14
						15
116,871,236	34,063,999	78,799,219	25,999,000			16
28,709,880	18,115,081	28,865,090	21,597,000			17
		-660,727	-688,700			18
3,272,229	705,288					19
557,506	10,140					20
351,329	344,794					21
						22
1,166,343,959	1,669,148,447	618,445,392	748,235,050	-4,836,453	-17,957,428	23
199,189,256	195,733,170	78,710,111	66,836,125	4,836,453	17,957,428	24

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	OTHER UTILITY		OTHER UTILITY		OTHER UTILITY	
	Current Year (k)	Previous Year (l)	Current Year (m)	Previous Year (n)	Current Year (o)	Previous Year (p)
1						
2						
3						
4						
5						
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STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
25	Net Utility Operating Income (Carried forward from page 114)		282,735,820	280,526,723
26	Other Income and Deductions			
27	Other Income			
28	Nonutilty Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)		4,761,696	3,367,871
30	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		4,864,302	3,119,010
31	Revenues From Nonutility Operations (417)		13,768	62,412
32	(Less) Expenses of Nonutility Operations (417.1)		10,047,313	8,104,213
33	Nonoperating Rental Income (418)		-28,147	
34	Equity in Earnings of Subsidiary Companies (418.1)	119	4,903,035	24,245,671
35	Interest and Dividend Income (419)		14,256,895	14,958,954
36	Allowance for Other Funds Used During Construction (419.1)		1,397,417	882,724
37	Miscellaneous Nonoperating Income (421)		2,451,969	2,582,781
38	Gain on Disposition of Property (421.1)		789,713	148,263
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		13,634,731	35,025,453
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)		651	735
42	Miscellaneous Amortization (425)	340		
43	Miscellaneous Income Deductions (426.1-426.5)	340	-1,295,579	10,255,520
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		-1,294,928	10,256,255
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263	36,000	36,000
47	Income Taxes-Federal (409.2)	262-263	-3,406,042	1,986,191
48	Income Taxes-Other (409.2)	262-263		
49	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	3,943,567	885,694
50	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,715,194	3,145,211
51	Investment Tax Credit Adj.-Net (411.5)			
52	(Less) Investment Tax Credits (420)			
53	TOTAL Taxes on Other Income and Deduct. (Total of 46 thru 52)		-2,141,669	-237,326
54	Net Other Income and Deductions (Enter Total lines 39, 44, 53)		17,071,328	25,006,524
55	Interest Charges			
56	Interest on Long-Term Debt (427)		182,197,660	178,146,978
57	Amort. of Debt Disc. and Expense (428)		1,926,427	1,889,073
58	Amortization of Loss on Reaquired Debt (428.1)		1,078,643	1,428,014
59	(Less) Amort. of Premium on Debt-Credit (429)			
60	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		123,445	123,445
61	Interest on Debt to Assoc. Companies (430)	340		
62	Other Interest Expense (431)	340	7,749,878	9,508,250
63	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,969,261	4,445,722
64	Net Interest Charges (Enter Total of lines 56 thru 63)		190,859,902	186,403,148
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)		108,947,246	119,130,099
66	Extraordinary Items			
67	Extraordinary Income (434)			
68	(Less) Extraordinary Deductions (435)			22,690,505
69	Net Extraordinary Items (Enter Total of line 67 less line 68)			-22,690,505
70	Income Taxes-Federal and Other (409.3)	262-263		-7,941,677
71	Extraordinary Items After Taxes (Enter Total of line 69 less line 70)			-14,748,828
72	Net Income (Enter Total of lines 65 and 71)		108,947,246	104,381,271

Schedule Page: 114 Line No.: 2 Column: c

Includes optimization transactions reported net in the income statement as required by EITF 02-03 effective after June 30, 2002. Prior periods have been reclassified to conform with the current presentation.

Schedule Page: 114 Line No.: 2 Column: d

Same as footnote immediately above.

Schedule Page: 114 Line No.: 2 Column: e

Same as footnote immediately above.

Schedule Page: 114 Line No.: 2 Column: f

Same as footnote immediately above.

Schedule Page: 114 Line No.: 4 Column: c

Same as footnote immediately above

Schedule Page: 114 Line No.: 4 Column: d

Same as footnote immediately above.

Schedule Page: 114 Line No.: 4 Column: e

Same as footnote immediately above.

Schedule Page: 114 Line No.: 4 Column: f

Same as footnote immediately above.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. 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)
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. 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.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. 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.
8. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance-Beginning of Year		26,668,818
2	Changes		
3	Adjustments to Retained Earnings (Account 439)		
4			
5			
6			
7			
8			
9	TOTAL Credits to Retained Earnings (Acct. 439)		
10	Licensed Hydro Project Excess Earnings	215.1	-325,669
11			
12			
13			
14			
15	TOTAL Debits to Retained Earnings (Acct. 439)		-325,669
16	Balance Transferred from Income (Account 433 less Account 418.1)		104,044,211
17	Appropriations of Retained Earnings (Acct. 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		
23	Dividends Declared-Preferred Stock (Account 437)		
24			-7,904,120
25			
26			
27			
28			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-7,904,120
30	Dividends Declared-Common Stock (Account 438)		
31			-89,416,892
32			
33			
34			
35			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-89,416,892
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-17,896,270
38	Balance - End of Year (Total 1,9,15,16,22,29,36,37)		15,170,078
	APPROPRIATED RETAINED EARNINGS (Account 215)		
39			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. 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)
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. 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.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. 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.
8. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
40			
41			
42			
43			
44			
45	TOTAL Appropriated Retained Earnings (Account 215)		
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)		
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		6,160,762
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		6,160,762
48	TOTAL Retained Earnings (Account 215, 215.1, 216) (Total 38, 47)		21,330,840
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)		
49	Balance-Beginning of Year (Debit or Credit)		22,841,201
50	Equity in Earnings for Year (Credit) (Account 418.1)		4,903,035
51	(Less) Dividends Received (Debit)		
52	Transfer to 216 due to closing of subsidiary		17,895,897
53	Balance-End of Year (Total lines 49 thru 52)		45,640,133

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

STATEMENT OF CASH FLOWS

1. If the notes to the cash flow statement in the respondents annual stockholders report are applicable to this statement, such notes should be included in page 122-123. Information about non-cash investing and financing activities should be provided on Page 122-123. Provide also on pages 122-123 a reconciliation between "Cash and Cash Equivalents at End of Year" with related amounts on the balance sheet.
2. Under "Other" specify significant amounts and group others.
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 on Page 122-123 the amount of interest paid (net of amounts capitalized) and income taxes paid.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
1	Net Cash Flow from Operating Activities:	
2	Net Income	108,947,247
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	203,073,235
5	Amortization of	
6	Utility Plant and Utility Plant Acquisition Adjustments	7,435,691
7	Property Losses	4,808,186
8	Deferred Income Taxes (Net)	129,527,458
9	Investment Tax Credit Adjustment (Net)	-660,727
10	Net (Increase) Decrease in Receivables	35,659,784
11	Net (Increase) Decrease in Inventory	21,755,085
12	Net (Increase) Decrease in Allowances Inventory	
13	Net Increase (Decrease) in Payables and Accrued Expenses	24,795,313
14	Net (Increase) Decrease in Other Regulatory Assets	29,738,339
15	Net Increase (Decrease) in Other Regulatory Liabilities	-636,806
16	(Less) Allowance for Other Funds Used During Construction	1,397,417
17	(Less) Undistributed Earnings from Subsidiary Companies	
18	Other Cash Flows from Operating Activities - SEE FOOTNOTE FOR DETAIL	182,501,793
19	Other	-8,147,919
20		
21		
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	737,399,262
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (including land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	-225,562,906
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	-1,397,417
31	Other (provide details in footnote):	
32		
33		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-224,165,489
35		
36	Acquisition of Other Noncurrent Assets (d)	
37	Proceeds from Disposal of Noncurrent Assets (d)	529,684
38		
39	Investments in and Advances to Assoc. and Subsidiary Companies	50,000
40	Contributions and Advances from Assoc. and Subsidiary Companies	
41	Disposition of Investments in (and Advances to)	
42	Associated and Subsidiary Companies	
43	Dividends Received from Investments (a)	311,968
44	Purchase of Investment Securities (a)	
45	Proceeds from Sales of Investment Securities (a)	830,417

STATEMENT OF CASH FLOWS

4. Investing Activities include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed on pages 122-123. Do not include on this statement the dollar amount of Leases capitalized per US of A General Instruction 20; instead provide a reconciliation of the dollar amount of Leases capitalized with the plant cost on pages 122-123.
5. Codes used:
(a) Net proceeds or payments.
(b) Bonds, debentures and other long-term debt.
(c) Include commercial paper.
(d) Identify separately such items as investments, fixed assets, intangibles, etc.
6. Enter on pages 122-123 clarifications and explanations.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
46	Loans Made or Purchased	
47	Collections on Loans	
48		
49	Net (Increase) Decrease in Receivables	
50	Net (Increase) Decrease in Inventory	
51	Net (Increase) Decrease in Allowances Held for Speculation	
52	Net Increase (Decrease) in Payables and Accrued Expenses	
53	Other (provide details in footnote): Restricted Cash	-18,871,226
54	Additions to Energy Conservation	-11,356,364
55	Other	-16,143,873
56	Net Cash Provided by (Used in) Investing Activities	
57	Total of lines 34 thru 55)	-268,814,883
58		
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
61	Long-Term Debt (b)	40,000,000
62	Preferred Stock	
63	Common Stock	
64	Other (provide details in footnote):	
65		
66	Net Increase in Short-Term Debt (c)	-307,828,000
67	Other (provide details in footnote):	
68		
69		
70	Cash Provided by Outside Sources (Total 61 thru 69)	-267,828,000
71		
72	Payments for Retirement of:	
73	Long-term Debt (b)	-117,000,000
74	Preferred Stock	-7,500,000
75	Common Stock	
76	Other (provide details in footnote): Investment from Puget Energy	115,736,213
77	Other	-136,771
78	Net Decrease in Short-Term Debt (c)	
79		
80	Dividends on Preferred Stock	-7,904,120
81	Dividends on Common Stock	-89,416,892
82	Net Cash Provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	-374,049,570
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22,57 and 83)	94,534,809
87		
88	Cash and Cash Equivalents at Beginning of Year	18,819,411
89		
90	Cash and Cash Equivalents at End of Year	113,354,220

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

Other Cash Flows from Operations:

Net (Increase)Decrease in Purchased Gas Liability	129,240,360
Amortization of Conservation Costs	18,368,517
Net (Increase)Decrease in Unbilled Revenue	34,892,916
Subtotal	**182,501,793**

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.

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

NOTES

To Consolidated Financial Statements of Puget Sound Energy

NOTE 1.

Summary of Significant Accounting Policies

These financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission 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. The primary differences include one-year presentation of the Statement of Cash Flows and Statement of Retained Earnings for FERC reporting requirements. Generally accepted accounting principles require the presentation of a Statement of Cash Flows and Statement of Retained Earnings for each year a Statement of Income is presented. Additionally, earnings per share are not presented in the accompanying FERC financial statements whereas earnings per share disclosure is required on the face of the Statement of Income under 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. classifies certain items in its Form 1 Balance Sheet (Primarily the classification of the components of accumulated deferred income taxes, 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 and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Basis of Presentation

Puget Energy, Inc. holds all the common shares of Puget Sound Energy, Inc. (PSE). The results of PSE are presented on a consolidated basis. PSE's consolidated financial statements include the accounts of PSE and its subsidiaries. The consolidated financial statements are presented after elimination of all significant intercompany items and transactions. Certain amounts previously reported have been reclassified to conform with current year presentations with no effect on total equity or net income. Investments in subsidiaries are stated on an equity basis inasmuch as the assets, liabilities, revenues and operating expenses of the subsidiaries are not material in relation to those of the Company.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Annual Reports on Form 10-K and Quarterly Reports on Form 10-Q are available at the Securities and Exchange Commission website at www.sec.gov or at Puget Sound Energy's website at www.pse.com.

Utility Plant

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

Non-Utility Property, Plant And Equipment

The costs of other property, plant and equipment are stated at cost. Expenditures for refurbishment and improvements that significantly add to productive capacity or extend useful life of an asset are capitalized. Replacement of minor items is expensed, on a current basis. Gains and losses on assets sold or retired are reflected in earnings.

Accounting for the impairment of long-lived assets

The Company evaluates impairment of long-lived assets in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 establishes accounting standards for determining if long-lived assets are impaired and how losses, if any, should be recognized. The Company believes that the net cash flows are sufficient to cover the carrying value of the assets.

Depreciation and Amortization

For financial statement purposes, the Company provides for depreciation and amortization on a straight-line basis. Amortization is comprised of software, small tools and office equipment. The depreciation of automobiles, trucks, power-operated equipment and tools is allocated to asset and expense accounts based on usage. The annual depreciation provision stated as a percent of average original cost of depreciable electric utility plant was 2.9% in 2002, 3.0% in 2001 and 2.9% in 2000; depreciable gas utility plant was 3.3% in 2002, 3.5% in 2001 and 3.3% in 2000; and depreciable common utility plant was 4.3% in 2002, 3.1% in 2001 and 1.9% in 2000.

Cash

All liquid investments with maturities of three months or less at the date of purchase are considered cash.

Material and Supplies

Material and supplies consists primarily of materials and supplies used in the operation and maintenance of the electric and gas systems, coal, diesel and natural gas held for generation, and natural gas and liquefied natural gas held in storage for future sales. These items are recorded at the lower of cost or market value, primarily using the weighted average cost method.

Regulatory Assets And Agreements

The Company accounts for its regulated operations in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation". SFAS No. 71 requires the Company to defer certain costs that would otherwise be charged to expense, if it is probable that future rates will permit recovery of such costs. Accounting under SFAS No. 71 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 applying SFAS No. 71, the Company must give consideration to changes in the level of demand or competition during the cost recovery period. In accordance with SFAS No. 71, the Company capitalizes certain costs in accordance with regulatory authority whereby those costs will be expensed and recovered in future periods.

The Company is allowed a return on the net regulatory assets and liabilities of 8.76% for both electric rates beginning July 1, 2002 and gas rates beginning September 1, 2002. The 2001 allowed rate of return was 8.94% for electric rates and 9.15% for gas rates. The net regulatory assets and liabilities at December 31, 2002 and 2001, included the following:

(Dollars in millions)	Remaining Amortization Period	2002	2001
Deferred income taxes		$167.1	$193.0
PURPA electric energy supply contract buyout costs	6 to 9 years	243.6	244.6
Investment in BEP exchange contract	14 years	51.1	54.7
Unamortized energy conservation charges	1 to 3 years	8.2	15.2
Storm damage costs – electric	4 years	21.9	26.6
Purchased gas receivable/(payable)	1 year	(83.8)	37.2
Deferred AFUDC	30 years	29.9	28.5
Environmental remediation		41.6	14.4
Various other regulatory assets	1 to 21 years	24.4	47.7
Deferred gains on property sales	3 years	(14.4)	(17.3)
Various other regulatory liabilities	1 to 17 years	(5.9)	(6.7)
Net regulatory assets and liabilities		$483.7	$637.9

If the Company, at some point in the future, determines that all or a portion of the utility operations no longer meet the criteria for continued application of SFAS No. 71, the Company would be required to adopt the provisions of SFAS No. 101, "Regulated Enterprises - Accounting for the Discontinuation of Application of FASB Statement No. 71". Adoption of SFAS No. 101 would require the Company to write off the regulatory assets and liabilities related to those operations not meeting SFAS No. 71 requirements. Discontinuation of SFAS No. 71 could have a material impact on the Company's financial statements.

The Company, in prior years, incurred costs associated with its 5% interest in a now-terminated nuclear generating project (identified herein as Investment in Bonneville Exchange Power (BEP)). Under terms of a settlement agreement with the Bonneville Power Administration (BPA), which settled claims of the Company relating to construction delays associated with that project, the Company is receiving power from the federal power system resources marketed by BPA. The Company's remaining investment in BEP is included in rate base and amortized on a straight-line basis over the life of the settlement agreement (amortization is included in purchased electricity expense). The Company has regulatory assets of approximately $243.6 million related to the buyout of purchased power and gas sales contracts of two non-utility generation projects. Washington Commission accounting orders have approved payments pursuant to these contracts for deferral and collection in rates over the remaining life of the energy supply contracts.

Allowance for Funds Used During Construction

The 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 principally 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 and is credited as a non-cash item to other income and interest charges currently. Cash inflow related to AFUDC does not occur until these charges are reflected in rates.

The AFUDC rate allowed by the Washington Commission for gas utility plant additions was 8.76% beginning September 1, 2002 and 9.15% in 2001 and 2000. The allowed AFUDC rate on electric utility plant was 8.76% beginning July 1, 2002 and 8.94% in 2001 and 2000. To the extent amounts calculated using this rate exceed the AFUDC calculated rate using the Federal Energy Regulatory Commission (FERC) formula, the Company capitalizes the excess as a deferred asset, crediting miscellaneous income. The amounts included in income were $2.6 million for 2002, $2.7 million for 2001 and $2.8 million for 2000. The deferred asset is being amortized over the average useful life of the Company's non-project utility plant.

Revenue Recognition

Operating utility revenues are recorded on the basis of service rendered, which includes estimated unbilled revenue.

Allowance for Doubtful Accounts

Allowance for doubtful accounts is calculated based upon historical write-offs as compared to operating revenues. The Company has also provided for a reserve for fiscal 2000 sales transactions related to the California Independent System Operator and counterparties based upon probability of collection. PSE's allowance for doubtful accounts for 2002 and 2001 was $43.5 million and $45.2 million, respectively.

Restricted Cash

Restricted cash represents cash to be used for specific purposes. Approximately $17.8 million in restricted cash was received from BPA under the amended Residential Purchase and Sale Agreement for residential and small farm customers who receive a credit on their bills for the Residential and Farm Energy Exchange credit tariff. The restricted amount is the excess paid by the BPA over the credit provided to these customers. All funds received will be credited to these customers in the future.

Self-Insurance

The Company currently has no insurance coverage for storm damage and is self-insured for a portion of the risk associated with comprehensive liability, industrial accidents and catastrophic property losses. With approval of the Washington Commission, PSE is able to defer for collection in future rates certain uninsured storm damage costs associated with major storms.

Federal Income Taxes

The Company normalizes, with the approval of the Washington Commission, certain income tax items. Deferred taxes have been determined under SFAS No. 109. Investment tax credits are deferred and amortized based on the average useful life of the related property in accordance with regulatory and income tax requirements.

Energy Conservation

The Company offers programs designed to help new and existing customers use energy efficiently. The primary emphasis is to provide information and technical services to enable customers to make energy efficient choices with respect to building design, equipment and building systems, appliance purchases and operating practices.

Since May 1997, the Company has recovered electric energy conservation expenditures through a tariff rider mechanism. The rider mechanism allows the Company to defer the conservation expenditures and amortize them to expense as PSE concurrently collects the conservation expenditures in rates over a one-year period. As a result of the rider, there is no effect on earnings per share.

Since 1995, the Company has been authorized by the Washington Commission to defer gas energy conservation expenditures and recover them through a tariff tracker mechanism. The tracker mechanism allows the Company to defer conservation expenditures and recover them in rates over the subsequent year. The tracker mechanism also allows the Company to recover an Allowance for Funds Used to Conserve Energy (AFUCE) on any outstanding balance that is not being recovered in rates.

Rate Adjustment Mechanism

The Company has a Power Cost Adjustment (PCA) mechanism that provides for an automatic rate adjustment if PSE's costs to provide customers' electricity falls outside certain bands from a normalized level of power costs established in the electric general rate case. The Company's cumulative maximum pre-tax earnings exposure due to power cost variations over the four year period ending June 30, 2006 is limited to $40 million plus 1% of the excess. All significant variable power supply cost drivers are included in the power cost adjustment mechanism (hydroelectric generation variability, market price variability for purchased power and surplus power sales, natural gas and coal fuel price variability, generation unit forced outage risk and wheeling cost variability). The mechanism apportions increases or decreases in power costs, on a graduated scale, between PSE and its customers.

The differences between the actual cost of the Company's gas supplies and gas transportation contracts and that currently allowed by the Washington Commission are deferred and recovered or repaid through the purchased gas adjustment (PGA) mechanism.

Natural Gas Off-System Sales and Capacity Release

The Company contracts for firm gas supplies and holds firm transportation and storage capacity sufficient to meet the expected peak winter demand for gas for space heating by its firm customers. Due to the variability in weather and other factors, however, the Company holds contractual rights to gas supplies and transportation and storage capacity in excess of its immediate requirements to serve firm customers on its distribution system for much of the year which, therefore, are available for third-party gas sales, exchanges and capacity releases. The Company sells excess gas supplies, enters into gas supply exchanges with third parties outside of its distribution area and releases to third parties excess interstate gas pipeline capacity and gas storage rights on a short-term basis to mitigate the costs of firm transportation and storage capacity for its core gas customers. The proceeds, net of transactional costs, from such activities are accounted for as reductions in the cost of purchased gas and passed on to customers through the PGA mechanism, with no direct impact on net income. As a result, the Company does not reflect sales revenue or associated cost of sales for these transactions in its income statement.

Energy Risk Management

The Company's energy related businesses are exposed to risks related to changes in commodity prices and volumetric changes in its loads and resources. The Company's energy risk management function manages the Company's core electric and gas supply portfolios to achieve three primary objectives:

(i) Ensure that physical energy supplies are available to serve retail customer requirements;
(ii) Manage portfolio risks to limit undesired impacts on financial results; and
(iii) Optimize the value of energy supply assets.

The Company enters into physical and financial instruments for the purpose of hedging commodity price risk. Gains or losses on these derivatives are accounted for pursuant to SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS No. 138. The Company has established policies and procedures to manage these risks. A Risk Management Committee separate from the business units that create these risks monitors compliance with policies and procedures. In addition, the Audit Committee of the Company's Board of Directors has oversight of the Risk Management Committee.

Accounting For Derivatives

On January 1, 2001, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by SFAS No. 138. SFAS No. 133 requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value. Certain contracts that would otherwise be considered derivatives are exempt from this SFAS if they qualify for a normal purchase and normal sale exception. The Company enters into both physical and financial contracts to manage its energy resource portfolio. The majority of these contracts qualify for the normal purchase and normal sale exception. However, certain of these contracts are derivatives and pursuant to SFAS No. 133 are reported at their fair value in the balance sheet. Changes in their fair value are reported in earnings unless they meet specific hedge accounting criteria, in which case changes in their fair market value are recorded in comprehensive income until the time when the transaction that they are hedging is recorded as income. The Company designates derivative instruments as a qualifying cash flow hedge if the change in the fair value of the derivative is highly effective at offsetting the changes in the fair value of an asset, liability or a forecasted transaction. To the extent that a portion of a derivative designated as a hedge is ineffective, changes in the fair value of the ineffective portion of that derivative are recognized currently in earnings. Finally, changes in the market value of derivative transactions related to obtaining gas for the Company's retail gas business are deferred as regulatory assets or liabilities as a result of the Company's PGA mechanism and recorded in earnings as the transactions are executed.

Stock-Based Compensation

The Company has various stock compensation plans, which are accounted for in accordance with APB No. 25, "Accounting for

Stock Issued to Employees," and related interpretations. The exercise price of stock options granted was the market value of the stock on the date of grant, so no compensation expense was recorded in the income statement for the options.

Debt Related Costs

Debt premium, discount and expenses are amortized over the life of the related debt. 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.

Accounts receivable securitization program

Rainier Receivables, Inc., is a wholly owned, bankruptcy-remote subsidiary of PSE formed in December 2002 for the purpose of purchasing customers' accounts receivable, both billed and unbilled, of PSE. Rainier Receivables and PSE have an agreement whereby Rainier Receivables can sell on a revolving basis, up to $150.0 million of those receivables. The current agreement expires in December 2005. Rainier Receivables is obligated to pay fees that approximate the third party purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. At December 31, 2002, there were no borrowings outstanding under the receivable securitization program.

New Accounting Pronouncements

In January 2003, the Financial Accounting Standards Board issued Interpretation No. 46 – "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 clarifies the application of Accounting Research Bulletin No. 51 – "Consolidated Financial Statements" to certain entities in which equity investors do not have controlling interest or sufficient equity at risk for the entity to finance its activities without additional financial support. This Interpretation requires that if a business entity has a controlling financial interest in a variable interest entity the financial statements must be included in the consolidated financial statements of the business entity. The adoption of this Interpretation for all interests in variable interest entities created after January 31, 2003 is effective immediately. For variable interest entities created before February 1, 2003, it is effective July 1, 2003. The Company is in the process of determining the impacts of this Interpretation.

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which is effective for fiscal years beginning after June 15, 2002. SFAS No. 143 requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost should be capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. The Company will adopt the new rules on asset retirement obligations on January 1, 2003. Application of the new rules is not expected to result in a material increase in net property, plant and equipment or expense.

The Emerging Issues Task Force of the Financial Accounting Standards Board (EITF or Task Force) at its June 2002 meeting came to a consensus on one of three items included in EITF Issue 02-3 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3). The Task Force has agreed that all mark-to-market gains and losses on energy trading contracts whether realized or unrealized will be shown net in the income statement (costs offset against revenues), irrespective of whether the contract is physically settled. The presentation is applicable to financial statements for periods ending after July 15, 2002. The Company performs risk management activities to optimize the value of energy supply and transmission assets and to ensure that physical energy supply is available to meet the customer demand loads. The Company also purchases energy when demand exceeds available supplies in its portfolio; likewise the Company makes sales to other utilities and marketers when surplus energy is available. These transactions are part of the Company's normal operations to meet retail load. The Company has reclassified all settled transactions that meet the definition of optimization (trading transactions that optimize hydro resources, and purchases and sales between trading points) net in the income statement to conform to the new presentation required under EITF 02-3. The Company previously reported these transactions when settled in a gross manner in the income statement in electric operating revenue and purchased electricity expense. Unrealized gains or losses on derivative instruments that are required to be marked-to-market remain reflected in unrealized (gain) loss on derivative instruments on Puget Energy's and PSE's income statement as required by SFAS No. 133. The adoption of EITF 02-3 does not have any impact on the previously reported net income of the Company. The following optimization transactions were recorded in electric operating revenue:

Years Ended December 31; (Dollars in thousands)	2002	2001	2000
Optimization sales	$66,992	$492,447	$133,361
Optimization purchases	64,448	487,431	139,376
Net margin on optimization transactions	$ 2,544	$ 5,016	$ (6,015)

NOTE 2.

Utility Plant

Utility plant at December 31, 2002 and 2001 included the following:

(Dollars in thousands) At December 31	2002	2001
Electric, gas and common utility plant classified by prescribed accounts at original cost:		
Distribution plant	$ 3,911,725	$ 3,736,590
Production plant	1,126,173	1,117,099
Transmission plant	368,959	361,662
General plant	365,409	376,119
Construction work in progress	108,658	123,307
Plant acquisition adjustment	76,623	76,623
Intangible plant (including capitalized software)	260,043	255,619
Underground storage	22,291	21,872
Liquefied natural gas	644	--
Plant held for future use	8,729	8,331
Other	4,807	4,807
Less accumulated provision for depreciation	(2,337,832)	(2,194,048)
Net utility plant	$ 3,916,229	$ 3,887,981

NOTE 3.

Preferred Stock

	Preferred Stock	
	Not Subject to Mandatory Redemption $25 Par Value	Subject to Mandatory Redemption $100 Par Value
Shares outstanding December 31, 1999	2,400,000	656,619
Acquired for sinking fund:		
2000	--	(75,000)
2001	--	(75,000)
2002	--	(75,000)
Called for redemption or reacquired and canceled:		
2000	--	--
2001	--	--
2002	--	--
Shares outstanding December 31, 2002	2,400,000	431,619

See "Consolidated Statements of Capitalization" for details on specific series.

The $25 par value 7.45% Series Preferred stock not subject to mandatory redemption may be redeemed at par on or after

November 1, 2003.

Preferred Stock Subject to Mandatory Redemption

The Company is required to deposit funds annually in a sinking fund sufficient to redeem the following number of shares of each series of preferred stock at $100 per share plus accrued dividends: 4.70% Series and 4.84% Series, 3,000 shares each and 7.75% Series, 37,500 shares. All previous sinking fund requirements have been satisfied. At December 31, 2002, there were 40,689 shares of the 4.70% Series and 24,192 shares of the 4.84% Series acquired by the Company and available for future sinking fund requirements. Upon involuntary liquidation, all preferred shares are entitled to their par value plus accrued dividends.

The preferred stock subject to mandatory redemption may also be redeemed by the Company at the following redemption prices per share plus accrued dividends: 4.70% Series, $101.00 and 4.84% Series, $102.00. The 7.75% Series may be redeemed by the Company, subject to certain restrictions, at $102.58 per share plus accrued dividends through February 15, 2003, and at per share amounts which decline annually to a price of $100 after February 15, 2007.

Company-Obligated, Mandatorily Redeemable Preferred Securities

In 1997 and 2001, the Company formed Puget Sound Energy Capital Trust I and Puget Sound Energy Capital Trust II, respectively, for the sole purpose of issuing and selling common and preferred securities (Trust Securities). The proceeds from the sale of Trust Securities were used to purchase Junior Subordinated Debentures (Debentures) from the Company. The Debentures are the sole assets of the Trusts and the Company owns all common securities of the Trusts.

The Debentures of Trust I and Trust II have an interest rate of 8.231% and 8.40%, respectively, and a stated maturity date of June 1, 2027 and June 30, 2041, respectively. The Trust Securities are subject to mandatory redemption at par on the stated maturity date of the Debentures. The Trust Securities in the Capital Trust I may be redeemed earlier, under certain conditions, at the option of the Company. The Capital Trust II Securities may be redeemed at any time on or after June 30, 2006 at par, under certain conditions, at the option of the Company. Dividends relating to preferred securities are included in interest expense. On February 26, 2003, the Company repurchased 19,750 shares of the 8.231% Trust Securities.

NOTE 4.

Dividend Restrictions

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock and long-term debt contained in the Company's Articles of Incorporation and Mortgage Indentures. Under the most restrictive covenants of PSE, earnings reinvested in the business unrestricted as to payment of cash dividends were approximately $202.7 million at December 31, 2002.

Under the general rate settlement, PSE must rebuild its common equity ratio to at least 39%, with milestones of 34%, 35% and 39% at the end of 2003, 2004 and 2005 respectively. If PSE should fail to meet the schedule, it would be subject to a 2% rate reduction penalty. The common equity ratio for PSE at December 31, 2002 was 36.1%.

NOTE 5.

Long-Term Debt

First Mortgage Bonds and Senior Notes
At December 31 (Dollars in thousands)

Series	Due	2002	2001	Series	Due	2002	2001
7.07%	2002	$ --	$ 27,000	6.51%	2008	$ 1,000	$ 1,000
7.15%	2002	--	5,000	6.53%	2008	3,500	3,500
7.53%	2002	--	10,000	7.61%	2008	25,000	25,000

7.625%	2002	--	25,000	6.46%	2009	150,000	150,000
7.85%	2002	--	30,000	6.61%	2009	3,000	3,000
7.91%	2002	--	20,000	6.62%	2009	5,000	5,000
6.20%	2003	3,000	3,000	7.12%	2010	7,000	7,000
6.23%	2003	1,500	1,500	7.96%	2010	225,000	225,000
6.24%	2003	1,500	1,500	7.69%	2011	260,000	260,000
6.30%	2003	20,000	20,000	8.20%	2012	30,000	30,000
6.31%	2003	5,000	5,000	8.59%	2012	5,000	5,000
6.40%	2003	11,000	11,000	6.83%	2013	3,000	3,000
7.02%	2003	30,000	30,000	6.90%	2013	10,000	10,000
6.25%	2004	40,000	--	7.35%	2015	10,000	10,000
6.07%	2004	10,000	10,000	7.36%	2015	2,000	2,000
6.10%	2004	8,500	8,500	6.74%	2018	200,000	200,000
7.70%	2004	50,000	50,000	9.57%	2020	25,000	25,000
7.80%	2004	30,000	30,000	8.25%	2022	25,000	25,000
6.92%	2005	11,000	11,000	8.39%	2022	7,000	7,000
6.93%	2005	20,000	20,000	8.40%	2022	3,000	3,000
6.58%	2006	10,000	10,000	7.19%	2023	3,000	3,000
8.06%	2006	46,000	46,000	7.35%	2024	55,000	55,000
8.14%	2006	25,000	25,000	7.15%	2025	15,000	15,000
7.02%	2007	20,000	20,000	7.20%	2025	2,000	2,000
7.75%	2007	100,000	100,000	7.02%	2027	300,000	300,000
7.04%	2007	5,000	5,000	7.00%	2029	100,000	100,000
8.40%	2007	10,000	10,000	Total		$1,932,000	$2,009,000

In January 2002, the Company issued $40.0 million of First Mortgage Bonds which are due January 2004. In February 2002, the Company filed a shelf-registration statement with the Securities and Exchange Commission for the offering on a delayed or continuous basis, of up to $500 million of any combination of common stock of Puget Energy, principal amount of Senior Notes secured by a pledge of First Mortgage Bonds, Unsecured Debentures or Trust Preferred Securities. In February 2003, the Company notified investors of its intent to call three series of first mortgage bonds totaling $20 million. The Company will repay the bonds using cash on hand.

Substantially all utility properties owned by the Company are subject to the lien of the Company's electric and gas mortgage indentures. To issue additional first mortgage bonds under these indentures, PSE's earnings available for interest must be at least twice the annual interest charges on outstanding first mortgage bonds. At December 31, 2002, the earnings available for interest were 2.4 times the annual interest charges.

Pollution Control Bonds

The Company has outstanding three series of Pollution Control Bonds. Amounts outstanding were borrowed from the City of Forsyth, Montana (the City). The City obtained the funds from the sale of Customized Pollution Control Refunding Bonds issued to finance pollution control facilities at Colstrip Units 3 and 4.

Each series of bonds is collateralized by a pledge of PSE's First Mortgage Bonds, the terms of which match those of the Pollution Control Bonds. No payment is due with respect to the related series of First Mortgage Bonds so long as payment is made on the Pollution Control Bonds.

At December 31 (Dollars in thousands)

Series	Due	2002	2001
1993 Series – 5.875%	2020	$ 23,460	$ 23,460
1991 Series – 7.05%	2021	27,500	27,500
1991 Series – 7.25%	2021	23,400	23,400
1992 Series – 6.80%	2022	87,500	87,500
Total		$161,860	$161,860

On February 19, 2003 the Board of Directors approved the refinancing of all Pollution Control Bonds series. It is anticipated that the refinancing of the Pollution Control Bonds will be completed in March or April 2003.

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)	2003	2004	2005	2006	2007	Thereafter
Maturities of:						
Long-term debt	$72,000	$138,473	$31,000	$81,000	$135,000	$1,636,360

NOTE 6.

Liquidity Facilities and Other Financing Arrangements

At December 31, 2002, PSE had short-term borrowing arrangements that included a $250 million unsecured 364-day line of credit with various banks and a $150 million 3-year receivables securitization program. These agreements replaced a $375 million line of credit, which would have expired on February 13, 2003. The new agreements provide PSE with the ability to borrow at different interest rate options and include variable fee levels. The line of credit allows the Company to make floating rate advances at prime plus a spread and Eurodollar advances at LIBOR plus a spread. The agreement contains "credit sensitive" pricing with various spreads associated with various credit rating levels. The agreement also allows for drawing letters of credit up to $50 million. The receivables securitization program allows the Company to draw against eligible receivables at a rate equal to that of high grade commercial paper.

In addition, PSE has agreements with several banks to borrow on an uncommitted, as available, basis at money-market rates quoted by the banks. There are no costs, other than interest, for these arrangements. PSE also uses commercial paper to fund its short-term borrowing requirements. The following table presents the liquidity facilities and other financing arrangements at December 31, 2002 and 2001.

(Dollars in thousands) At December 31	2002	2001
Short-term borrowings outstanding:		
Commercial paper notes	$ 30,340	$123,168
Bank line of credit borrowings	--	215,000
Weighted average interest rate	2.37%	2.68%
PSE credit availability (1)	250,000	375,000
PSE receivable securitization program	150,000	--

(1) Provides liquidity support for PSE's outstanding commercial paper in the amount of $30.3 million and $338.2 million for 2002 and 2001, respectively, effectively reducing the available borrowing capacity under these credit lines to $219.7 million and $36.8 million, respectively.

The Company has, on occasion, entered into interest rate swap agreements to reduce the impact of changes in interest rates on portions of its floating-rate debt. There were no such agreements outstanding at December 31, 2002 and 2001.

NOTE 7.

Estimated Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments at December 31, 2002 and 2001:

(Dollars in millions)	2002 Carrying Amount	2002 Fair Value	2001 Carrying Amount	2001 Fair Value
Financial assets:				
Cash	$176.7	$176.7	$ 92.3	$ 92.3
Restricted cash	17.8	17.8	--	--
Equity securities (2)	10.4	10.4	12.8	12.8
Notes receivable and other	41.5	41.5	40.0	40.0
Energy derivatives	13.6	13.6	6.6	6.6
Financial liabilities:				
Short-term debt	30.3	30.3	338.2	338.2
Preferred stock subject to mandatory redemption	43.2	42.4	50.7	49.3
Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation	300.0	303.1	300.0	301.8
Long-term debt	2,093.9	2,252.7	2,170.9	2,055.4
Energy derivatives	2.4	2.4	35.2	35.2

(2) The 2002 and 2001 carrying amount includes an adjustment of $2.4 million and $4.5 million, respectively, to report the available-for-sale securities at market value. This amount (or unrealized gain) has been included as a component of other comprehensive income net of deferred taxes of $0.8 million and $1.6 million for 2002 and 2001, respectively.

The fair value of outstanding bonds including current maturities is estimated based on quoted market prices.

The preferred stock subject to mandatory redemption and corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation is estimated based on dealer quotes.

The carrying value of short-term debt and notes receivable are considered to be a reasonable estimate of fair value. The carrying amount of cash, which includes temporary investments with original maturities of three months or less, is also considered to be a reasonable estimate of fair value.

Derivative instruments have been used by the Company on a limited basis and are recorded at fair value. The Company has a policy that financial derivatives are to be used only to mitigate business risk.

NOTE 8.

Supplementary Income Statement Information

(Dollars in thousands)	2002	2001	2000
Taxes other than income taxes:			
Real estate and personal property	$48,408	$ 41,588	$ 47,357
State business	77,527	84,735	83,485
Municipal and occupational	67,770	71,819	65,155
Other	24,463	29,084	30,073
Total taxes other than income taxes	$218,168	$ 227,226	$ 226,070
Charged to:			

Operating expense	$202,381	$ 207,365	$ 202,398
Other accounts, including construction work in progress	15,787	19,861	23,672
Total taxes other than income taxes	$218,168	$ 227,226	$ 226,070

NOTE 9.

Leases

All of PSE's leases are operating leases. Certain leases contain purchase options, renewal and escalation provisions. Operating lease payments net of sublease receipts were:

(Dollars in thousands) At December 31	Operating
2002	$20,176
2001	20,135
2000	18,239

Payments received for the sublease of properties were approximately $2.6 million, $2.5 million, and $2.4 million for the years ended December 31, 2002, 2001, and 2000, respectively.

Future minimum lease payments for non-cancelable leases net of sublease receipts are:

(Dollars in thousands) At December 31	Operating
2003	$12,644
2004	10,404
2005	6,446
2006	6,502
2007	6,468
Thereafter	9,350
Total minimum lease payments	$51,814

Future minimum sublease receipts for non-cancelable subleases are $1 million for 2003.

NOTE 10.

Income Taxes

The details of income taxes are as follows:

(Dollars in thousands)	2002	2001	2000
Charged to operating expense:			
Current - federal	$(81,839)	$ 58,331	$ 128,138
Current - state	(548)	1,232	832
Deferred – net federal	135,884	18,040	1,557
Deferred-net state	--	--	--
Deferred investment tax credits	(661)	(688)	(704)
Total charged to operations	52,836	76,915	129,823
Charged to miscellaneous income:			
Current	(3,406)	6,272	7,843

Deferred – net	1,228	(2,259)	(10,150)
Total charged to miscellaneous income	(2,178)	4,013	(2,307)
Cumulative effect of accounting change	--	(7,942)	--
Total income taxes	$50,658	$ 72,986	$127,516

The following is a reconciliation of the difference between the amount of income taxes computed by multiplying pre-tax book income by the statutory tax rate and the amount of income taxes in the Consolidated Statements of Income for the Company:

(Dollars in thousands)	2002	2001	2000
Income taxes at the statutory rate	$55,862	$ 62,079	$ 112,471
Increase (decrease):			
Depreciation expense deducted in the financial statements in excess of tax depreciation, net of depreciation treated as a temporary difference	10,041	11,726	10,807
AFUDC included in income in the financial statements but excluded from taxable income	(1,387)	(2,126)	(3,274)
Accelerated benefit on early retirement of depreciable assets	(1,469)	(319)	(834)
Investment tax credit amortization	(661)	(689)	(704)
Energy conservation expenditures - net	6,259	6,859	10,634
Tax benefit of reduced salvage values	(10,193)	--	--
State income taxes net of the federal income tax benefit	(356)	801	541
Other – net	(7,438)	(5,345)	(2,125)
Total income taxes	$50,658	$ 72,986	$127,516
Effective tax rate	31.7%	41.1%	39.7%

The following are the principal components of income taxes as reported:

(Dollars in thousands)	2002	2001	2000
Current income taxes – federal	$(85,245)	$ 64,603	$ 135,981
Current income taxes – state	(548)	1,232	832
Deferred income taxes:			
Conservation tax settlement	--	963	1,776
Deferred FAS-133	4,064	(4,028)	--
Cabot preferred stock sale	--	--	(10,635)
Deferred taxes related to insurance reserves	(1,662)	(1,225)	(384)
Residential Purchase and Sale Agreement - net	--	3,390	2,226
Normalized tax benefits of the accelerated cost recovery system	29,197	11,423	10,931
Energy conservation program	(96)	(1,337)	(1,666)
Environmental remediation	1,392	1,326	721
WNP 3 tax settlement	(1,126)	(1,126)	(1,126)
Demand charges	(8)	(98)	(79)
Deferred revenue	612	(5,904)	--
Software amortization	35,373	--	--
Capitalized overhead costs deducted for tax			

purposes	72,220	--	--
Allowance for doubtful accounts	--	--	(13,821)
Other	(2,854)	4,455	3,464
Total deferred income taxes	137,112	7,839	(8,593)
Deferred investment tax credits - net of amortization	(661)	(688)	(704)
Total income taxes	$50,658	$ 72,986	$ 127,516

The Company's deferred tax liability at December 31, 2002 and 2001 is comprised of amounts related to the following types of temporary differences:

(Dollars in thousands)	2002	2001
Utility plant	$578,137	$ 570,982
Energy conservation charges	16,473	23,782
Contributions in aid of construction	(44,770)	(36,044)
Bonneville Exchange Power	15,537	17,897
Cabot gas contract purchase	4,157	4,477
Deferred revenue	(5,292)	(5,904)
Software amortization	41,408	--
Capitalized overhead costs	72,220	--
Other	37,709	25,811
Total	$715,579	$ 601,001

PSE's totals of $715.6 million and $601.0 million for 2002 and 2001 consist of deferred tax liabilities of $824.2 million and $707.4 million net of deferred tax assets of $108.6 million and $106.4 million, respectively.

Deferred tax amounts shown above result from temporary differences for tax and financial statement purposes. Deferred tax provisions are not recorded in the income statement for certain temporary differences between tax and financial statement purposes because they are not allowed for ratemaking purposes.

The Company calculates its deferred tax assets and liabilities under SFAS No. 109, "Accounting for Income Taxes". SFAS No. 109 requires recording deferred tax balances, at the currently enacted tax rate, for all temporary differences between the book and tax bases of assets and liabilities, including temporary differences for which no deferred taxes had been previously provided because of use of flow-through tax accounting for ratemaking purposes. Because of prior and expected future ratemaking treatment for temporary differences for which flow-through tax accounting has been utilized, a regulatory asset for income taxes recoverable through future rates related to those differences has also been established by PSE. At December 31, 2002, the balance of this asset was $167.1 million.

NOTE 11.

Retirement Benefits

The Company has a defined benefit pension plan covering substantially all of its utility employees. Benefits are a function of both age and salary. Additionally, Puget Sound Energy maintains a non-qualified supplemental retirement plan for officers and certain director-level employees.

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits for retired employees. These benefits are provided principally through an insurance company whose premiums are based on the benefits paid during the year.

(Dollars in thousands)	Pension Benefits 2002	Pension Benefits 2001	Other Benefits 2002	Other Benefits 2001
Change in benefit obligation:				
Benefit obligation at beginning of year	$400,461	$ 366,482	$29,115	$ 27,568
Service cost	8,474	9,862	168	243
Interest cost	25,858	26,734	1,930	2,022
Amendments (1)	3,073	3,984	3,493	--
Actuarial loss	2,055	15,417	(419)	1,101
Plan curtailment (2)	(9,518)	--	(553)	--
Special adjustments (2)	10,872	--	--	--
Benefits paid	(71,583)	(22,018)	(2,041)	(1,819)
Benefit obligation at end of year	$369,692	$400,461	$31,693	$29,115
Change in plan assets:				
Fair value of plan assets at beginning of year	$443,512	$496,468	$15,978	$15,661
Actual return on plan assets	(40,849)	(32,025)	650	595
Employer contribution	12,880	1,087	1,573	1,541
Benefits paid	(71,583)	(22,018)	(2,041)	(1,819)
Fair value of plan assets at end of year	$343,960	$ 443,512	$16,160	$15,978
Funded status	$(25,732)	$ 43,051	$(15,533)	$(13,137)
Unrecognized actuarial gain	66,784	(27,035)	(1,878)	(1,944)
Unrecognized prior service cost	18,228	20,250	3,021	(361)
Unrecognized net initial (asset)/obligation	(2,371)	(3,873)	4,201	6,894
Net amount recognized	$ 56,909	$ 32,393	$(10,189)	$ (8,548)
Amounts recognized on statement of financial position consist of:				
Prepaid benefit cost	$73,361	$ 54,335	$(10,189)	$ (8,548)
Accrued benefit liability	(34,253)	(37,002)	--	--
Intangible asset	10,555	9,912	--	--
Accumulated other comprehensive income	7,246	5,148	--	--
Net amount recognized	$ 56,909	$ 32,393	$(10,189)	$ (8,548)

(1) In 2002, the Company had $3.1 million in pension benefits plan amendments due to changes in employment contracts, the addition of new entrants to the plan and the vesting of certain nonvested participants who were affected by the transition of service jobs to service providers. The Company had $3.5 million in other benefits plan amendments due to an increase in the Company's contribution to the retiree medical plan.

(2) *In 2002, the Company had a $9.5 million curtailment credit and $9.2 million in special adjustments to the pension benefit plan related to the transition of service jobs to service providers. The Company also had a $1.7 million special adjustment to the pension benefit plan related to the non-qualified pension benefit plan required to reflect the special benefit agreement given upon termination of a plan participant.*

In accounting for pension and other benefits costs under the plans, the following weighted average actuarial assumptions were used:

	Pension Benefits 2002	Pension Benefits 2001	Pension Benefits 2000	Other Benefits 2002	Other Benefits 2001	Other Benefits 2000
Discount rate	6.75%	7.25%	7.5%	6.75%	7.25%	7.5%
Return on plan assets	8.25%	9.50%	9.75%	6-7.00%	6-8.25%	6-8.5%
Rate of compensation increase	4.50%	5.0%	5.0%	--	--	--
Medical trend rate	--	--	--	10.00%	6.5%	7.0%

(Dollars in thousands)	Pension Benefits 2002	2001	2000	Other Benefits 2002	2001	2000
Components of net periodic benefit cost:						
Service cost	$ 8,474	$ 9,862	$ 9,005	$ 168	$ 243	$ 224
Interest cost	25,858	26,734	25,500	1,930	2,022	1,965
Expected return on plan assets	(43,032)	(46,222)	(42,280)	(906)	(947)	(892)
Amortization of prior service cost	2,990	2,960	2,884	90	(34)	(34)
Recognized net actuarial gain	(5,120)	(7,570)	(6,851)	(229)	(109)	(195)
Amortization of transition (asset)/obligation	(1,136)	(1,230)	(1,230)	470	627	627
Plan curtailment	(1,353)	--	--	1,691	--	--
Special recognition of prior service costs	1,683	108	77	--	--	--
Net pension benefit cost (income)	$(11,636)	$(15,358)	$(12,895)	$3,214	$1,802	$1,695

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the non-qualified pension plan, which has accumulated benefit obligations in excess of plan assets, were $39.4 million, $34.2 million, and $0, respectively, as of December 31, 2002. For the qualified pension plan the projected benefit obligation, accumulated benefit obligation and fair value of plan assets were $330.3 million, $310.1 million, and $344.0 million, respectively as of December 31, 2002.

The assumed medical inflation rate is 10.0% in 2003 decreasing 1.0% per year to 6.0%. A 1% change in the assumed medical inflation rate would have the following effects:

(Dollars in thousands)	2002 1% increase	2002 1% decrease	2001 1% increase	2001 1% decrease
Effect on service and interest cost components	$580	$(515)	$ 625	$ (558)
Effect on post retirement benefit obligation	36	(32)	47	(42)

NOTE 12.

Employee Investment Plans and Employee Stock Purchase Plan

The Company has qualified Employee Investment Plans 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 $6.1 million, $6.8 million, and $7.2 million for the years 2002, 2001 and 2000, respectively. The Employee Investment Plan eligibility requirements are set forth in the plan documents.

The Company also has an Employee Stock Purchase Plan which was approved by shareholders on May 19, 1997, and commenced July 1, 1997, under which options are granted to eligible employees who elect to participate in the plan on January 1st and July 1st of each year. Participants are allowed to exercise those options six months later to the extent of payroll deductions or cash payments accumulated during that six-month period. The option price under the plan during 2002 was 85% of either the fair market value of the common stock at the grant date or the fair market value at the exercise date, whichever was less. Prior to 2002 the Company purchased stock for the plan on the open market. Starting with the purchase rights accumulated under the July 1, 2002 grant the Company began issuing rather than purchasing stock. The Company's contributions to the plan were $0.1 million, $0.1 million and $0.3 million for 2002, 2001 and 2000, respectively.

NOTE 13.

Stock-based Compensation Plans

The Company has various stock compensation plans accounted for according to APB No. 25, "Accounting for Stock Issued to

Employees," and related interpretations. Total compensation expense related to the plans was $6.3 million, $2.1 million and $3.9 million in 2002, 2001 and 2000 respectively.

The Company's shareholder approved Long-Term Incentive Plan (LTI Plan) encompasses many of the awards granted to employees. Established in 1995 and amended and restated in 1997, the LTI Plan applies to officers and key employees of the Company. Awards granted under this plan include stock awards, performance awards, or other stock-based awards as defined by the plan. Any shares awarded are purchased on the open market. The maximum number of shares that may be purchased for the LTI Plan is 1,200,000.

Performance Share Grants

Each year the Company awards performance share grants under the LTI Plan. These are granted to key employees and vest at the end of four years with the final number of shares awarded depending on a performance measure. The Company records compensation expense related to the shares based on the performance measure and changes in the market price of the stock. Compensation expense related to performance share grants was $5.5 million, $2.3 million and $3.2 million for 2002, 2001 and 2000, respectively. The fair value of the performance awards granted in 2002, 2001 and 2000 is $14.82, $17.86 and $14.19 respectively. 247,184 performance awards were granted in 2002, 183,881 in 2001 and 204,044 in 2000. As of December 31, 2002, there are four grant cycles active for a total of 571,719 share grants outstanding although they may not all be awarded.

Stock Options

In 2002, Puget Energy's Board of Directors granted 40,000 stock options under the LTI Plan and an additional 260,000 options outside of the LTI Plan for a total of 300,000 non-qualified stock options to the new president and chief executive officer. These options were awarded at the grant date market price of $22.51 and vest yearly over four and five years although vesting is accelerated under certain conditions. The options expire 10 years from the grant date. As of December 31, 2002, no options were exercisable. The grant date fair value of the options is $3.37. Following the intrinsic value method of APB 25, no compensation expense was recorded for these options.

Restricted Stock

In 2002, the Company granted 30,000 shares of restricted stock under the LTI Plan to be purchased on the open market. The shares vest monthly with all of the shares vested by December 2003. The Company also issued 50,000 shares of restricted stock outside of the LTI Plan as approved by the Puget Energy Board of Directors. These shares were recorded as a separate component of stockholders equity and vest at the rate of 20% per year. Compensation expense related to the restricted shares was $0.5 million in 2002. No restricted shares were issued in 2001 and 2000. Dividends are paid on all outstanding restricted stock and are accounted for as a Puget Energy stock dividend, not as compensation expense. At December 31, 2002 the weighted average grant date fair value for all outstanding shares of restricted stock was $21.94.

Employee Stock Purchase Plan

The Company has a shareholder-approved Employee Stock Purchase Plan (ESPP) open to all employees. Offerings occur at six month intervals at the end of which the participating employees receive shares for 85% of the lower of the stock's fair market price at the beginning or the end of the six month period. A maximum of 500,000 shares may be sold to employees under the plan. The Company purchased shares for the plan on the open market up until the most recent offering at which time common stock was issued rather than purchased. The Company currently plans to issue common stock for the ESPP. In 2002, 19,407 shares were purchased for the plan and 18,252 shares were issued. 45,659 shares and 48,513 shares were purchased in 2001 and 2000 respectively. At December 31, 2002 298,602 shares may still be sold to employees under the plan. Dividends are paid on purchased shares and are accounted for as a Puget Energy stock dividend, not as compensation expense. The weighted average fair value of the purchase rights granted in 2002, 2001 and 2000 was $4.19, $4.35 and $3.90 respectively.

Non-Employee Director Stock Plan

The Company has a director stock plan created in 1998 for all non-employee directors of Puget Energy/PSE. Under the plan non-employee directors receive part of their quarterly retainer in Company stock and may receive their entire retainer in Company stock if they choose. The compensation expense related to the director stock plan was $0.2 million, $0.1 million and $0.3 million in 2002, 2001, and 2000, respectively. The Company purchases stock for this plan on the open market up to a maximum of 100,000 shares. As of December 31, 2002, 6,916 shares have been purchased for the director stock plan and 36,117 deferred, for a total of 43,033 shares.

Other Plans

In addition to current stock compensation plans, the Company also has outstanding shares related to two plans that were in effect prior to the 1997 merger between Puget Sound Power and Light (PSP&L) and Washington Energy Company (WECO). There are 30,800 vested, unexercised stock appreciation rights from the PSP&L Incentive Plan Awards granted to executives of PSP&L. These were granted in 1993 and 1994 for $27.63 and $20.75, respectively, and expire 10 years after the grant date. There are also 17,960 vested, unexercised options from the WECO Incentive Stock Option Plan granted to key employees of WECO. The options were granted between 1993 and 1996 for prices ranging from $15.55 to $23.11 and expire 10 years from the date of grant. These are generally paid out as stock appreciation rights at the discretion of the grantees. The Company records compensation expense each quarter related to the PSP&L and WECO shares as the difference between the exercise price and the current market price. Compensation expense related to the WECO plan was near $0 in 2002, $(0.2) million in 2001 and $0.2 million in 2000. Compensation expense related to the PSP&L plan was near $0 in 2002, $(0.1) million in 2001, and $0.2 million in 2000.

The Company used the Black-Scholes option pricing model to determine the fair value of certain stock based awards to employees. The following assumptions were used for awards granted in 2002, 2001 and 2000:

	2002	2001	2000
Stock Options			
Risk-free interest rate	4.32%	-	-
Expected lives - years	4.50	-	-
Expected stock volatility	23.62%	-	-
Dividend yield	5.00%	-	-
Performance Awards			
Risk-free interest rate	4.00%	4.99%	6.66%
Expected lives - years	4.00	4.00	4.00
Expected stock volatility	23.71%	20.76%	18.59%
Dividend yield	8.85%	7.67%	9.14%
Employee Stock Purchase Plan			
Risk-free interest rate	1.65%	4.26%	5.59%
Expected lives - years	0.50	0.50	0.50
Expected stock volatility	26.97%	19.04%	22.73%
Dividend yield	5.81%	7.72%	8.98%

NOTE 14.

Other Investments

In March 1998, the Company entered into an agreement with Schlumberger North America (Schlumberger) (formerly known as CellNet Data Services Inc.), under which the Company would lend Schlumberger up to $35 million in the form of multiple draws so that Schlumberger could finance an Automated Meter Reading (AMR) network system to be deployed in the Company's service territory. In September 1999, the Company announced it was expanding its AMR network system from 800,000 meters to 1,325,000 meters and as a result increased the authorized loan amount to $72 million. As of December 31, 2000, the outstanding loan balance was $51.9 million. In August 2001, Schlumberger paid off its outstanding loan balance of $64.1 million.

NOTE 15.

Commitments and Contingencies

Commitments – Electric

For the twelve months ended December 31, 2002, approximately 22.5% of the Company's energy output was obtained at an average cost of approximately 13.96 mills per kWh through long-term contracts with several of the Washington Public Utility Districts (PUDs) owning hydroelectric projects on the Columbia River.

The purchase of power from the Columbia River projects is on a "cost-of-service" basis under which the Company pays a proportionate share of the annual cost of each project in direct proportion to the amount of power annually purchased by the Company from such project. Such payments are not contingent upon the projects being operable. These projects are financed through substantially level 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 lives of the contracts.

As of December 31, 2002, the Company was entitled to purchase portions of the power output of the PUDs' projects as set forth in the following tabulation:

			Bonds Outstanding	Company's Annual Amount Purchasable (Approximate)		
Project	Contract(1) Exp. Date	License(2) Exp. Date	12/31/02 (3) (Millions)	% of Output	Megawatt Capacity	Costs (4) (Millions)
Rock Island						
Original units	2012	2029	$ 102.4	50.0	455	$43.3
Additional units	2012	2029	333.7	85.0		
Rocky Reach	2011	2006	408.9	38.9	505	26.2
Wells	2018	2012	165.5	31.3	261	9.8
Priest Rapids	2005	2005	150.4	8.0	72	2.3
Wanapum	2009	2005	136.2	10.8	98	4.1
Total			$1,297.1		1,391	$85.7

(1)On December 28, 2001, PSE signed a contract offer for new contracts for the Priest Rapids and Wanapum Developments. On April 12, 2002, PSE signed amendments to those agreements which are technical clarifications of certain sections of the agreements. Under the terms of these contracts, PSE will continue to obtain capacity and energy for the term of any new FERC license to be obtained by Grant County PUD. The new contracts begin in November of 2005 for the Priest Rapids Development and in November of 2009 for the Wanapum Development. Unlike the current contracts, in the new contracts PSE's share of power from developments declines over time as Grant County PUD's load increases.

On March 8, 2002, the Yakama Nation filed a complaint with FERC which alleged that Grant County's new contracts unreasonably restrain trade and violate various sections of the Federal Power Act and Public Law 83-544. On November 21, 2002, FERC dismissed the complaint while agreeing that certain aspects of the complaint had merit. As a result, they have ordered Grant County PUD to remove specific Sections of the contract which constrain the parties to the Grant County PUD contracts from competing with Grant County PUD for a new license. A rehearing has been requested..

(2)The Company is unable to predict whether the licenses under the Federal Power Act will be renewed to the current licensees. FERC has issued orders for the Rocky Reach, Wells and Priest Rapids/Wanapum projects under Section 22 of the Federal Power Act, which affirm the Company's contractual rights to receive power under existing terms and conditions even if a new licensee is granted a license prior to expiration of the contract term.

(3)The contracts for purchases initially were generally coextensive with the term of the PUD bonds associated with the project. Under the terms of some financings and refinancings, however, long-term bonds were sold to finance certain assets whose estimated useful lives extend beyond the expiration date of the power sales contracts. Of the total outstanding bonds sold for each project, the percentage of principal amount of bonds which mature beyond the contract expiration date are: 41.7% at Rock Island; 55.1% at Rocky Reach; 89.7% at Priest Rapids; 67.9% at Wanapum; and 5.7% at Wells.

(4)The components of 2002 costs associated with the interest portion of debt service are: Rock Island, $21.1 million for all units; Rocky Reach, $8.0 million; Wells, $2.6 million; Priest Rapids, $0.7 million; and Wanapum, $0.8 million.

The Company's estimated payments for power purchases from the Columbia River are $92.7 million for 2003, $82.6 million for 2004, $78.9 million for 2005, $76.5 million for 2006, $79.3 million for 2007 and in the aggregate, $377.9 million thereafter through 2018.

The Company also has numerous long-term firm purchased power contracts with other utilities in the region. The Company is generally not obligated to make payments under these contracts unless power is delivered. The Company's estimated payments for firm power purchases from other utilities, excluding the Columbia River projects, are $124.0 million for 2003, $75.5 million for 2004, $76.3 million for 2005, $77.9 million for 2006, $80.6 million for 2007 and in the aggregate, $500.3 million thereafter through 2037. These contracts have varying terms and may include escalation and termination provisions.

As required by the federal Public Utility Regulatory Policies Act (PURPA), PSE entered into long-term firm purchased power contracts with non-utility generators. The Company purchases the net electrical output of four significant projects at fixed and annually escalating prices, which were intended to approximate the Company's avoided cost of new generation projected at the time these agreements were made. The Company's estimated payments under these contracts are $202.7 million for 2003, $215.0 million for 2004, $220.3 million for 2005, $227.6 million for 2006, $210.4 million for 2007 and in the aggregate, $946.5 million thereafter through 2012.

The following table summarizes the Company's estimated obligations for future power purchases:

(Dollars in millions)	2003	2004	2005	2006	2007	2008 & There-after	Total
Columbia River Projects	$ 92.7	$ 82.6	$ 78.9	$ 76.5	$ 79.3	$ 377.9	$ 787.9
Other utilities	124.0	75.5	76.3	77.9	80.6	500.3	934.6
Non-utility generators	202.7	215.0	220.3	227.6	210.4	946.5	2,022.5
Total	$419.4	$373.1	$375.5	$382.0	$370.3	$1,824.7	$3,745.0

Total purchased power contracts provided the Company with approximately 12.1 million, 11.9 million and 15.1 million MWh of firm energy at a cost of approximately $466.1 million, $496.3 million, and $506.5 million for the years 2002, 2001 and 2000, respectively.

As part of its electric operations and in connection with the 1997 restructuring of the Tenaska Power Purchase Agreement, PSE is obligated to deliver to Tenaska up to 48,000 MMBtu per day of natural gas for operation of Tenaska's cogeneration facility. This obligation continues for the remaining term of the agreement, provided that no deliveries are required during the month of May. The price paid by Tenaska for this gas is reflective of the daily price of gas at the United States/Canada border near Sumas, Washington.

The following table indicates the Company's percentage ownership and the extent of the Company's investment in jointly-owned generating plants in service at December 31, 2002:

(Dollars in millions)	Energy Source (Fuel)	Company's Ownership Share	Company's Share: Plant in Service At Cost	Company's Share: Accumulated Depreciation
Colstrip 1 and 2	Coal	50%	$201	$128
Colstrip 3 and 4	Coal	25%	458	226

Financing for a participant's ownership share in the projects is provided for by such participant. The Company's share of related operating and maintenance expenses is included in corresponding accounts in the Consolidated Statements of Income.

As part of its electric operations and in connection with the 1999 buy-out of the Cabot gas supply contract, PSE is obligated to deliver to Encogen up to 21,800 MMBtu per day of natural gas for operation of the Encogen cogeneration facility. This obligation continues for the remaining term of the original Cabot agreement. The Company entered into a financial arrangement to hedge a portion of future gas supply costs associated with this obligation, 10,000 MMBtu per day, for the remaining term of the agreement. The Company has a maximum financial obligation under this hedge agreement of $8.1 million in 2002, $8.2 million in 2003, $8.5 million in 2004, $8.7 million in 2005, $8.9 million in 2006 and $13.9 million thereafter. Depending on actual market prices, these costs will be partially, or perhaps entirely, offset by floating price payments received under the hedge arrangement. Encogen has two gas supply agreements that comprise 40% of the plant's requirements with remaining terms of 6.5 years. The obligations under these contracts are $12.8 million in 2002, $13.5 million in 2003, $14.2 million in 2004, $14.9 million in 2005, $15.6 million in 2006 and $25.0 million in the aggregate thereafter.

PSE enters into short-term energy supply contracts to meet its core customer needs. These contracts are classified as normal purchases and sales in accordance with SFAS No. 133. Commitments under these contracts for 2003 and 2004 total $47.2 million and $1.8 million, respectively.

Gas Supply

The Company has also entered into various firm supply, transportation and storage service contracts in order to assure adequate availability of gas supply for its firm customers. Many of these contracts, which have remaining terms from less than 1 year to 21 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage. Certain of PSE's firm gas supply agreements also obligate the Company to purchase a minimum annual quantity at market-based contract prices. Generally, if the minimum volumes are not purchased and taken during the year, the Company is obligated to either: 1) pay a monthly or annual gas inventory charge calculated as a percentage of the then-current contract commodity price times the minimum quantity not taken; or 2) pay for gas not taken. Alternatively, under some of the contracts, the supplier may exercise a right to reduce its subsequent obligation to provide firm gas to the Company. The Company incurred demand charges in 2002 for firm gas supply, firm transportation service and firm storage and peaking service of $27.4 million, $49.0 million and $6.4 million, respectively. WNG Cap I incurred demand charges in 2002 for firm transportation service of $9.4 million.

The following tables summarize the Company's obligations for future demand charges through the primary terms of its existing contracts and the minimum annual take requirements under the gas supply agreements. The quantified obligations are based on current contract prices and FERC authorized rates, which are subject to change.

Demand Charge Obligations

(Dollars in millions)	2003	2004	2005	2006	2007	2008 & There-after	Total
Firm gas supply	$20.6	$ 12.5	$ 1.1	$ 1.1	$ 1.2	$ 2.8	$ 39.3
Firm transportation service	54.6	44.7	11.6	11.6	11.6	82.1	216.2
Firm storage service	7.2	8.6	7.7	7.7	7.7	55.9	94.8
Total	$82.4	$65.8	$20.4	$20.4	$20.5	$140.8	$350.3

Minimum Annual Take Obligations

(Therms in thousands)	2003	2004	2005	2006	2007	2008 & There-after	Total
Firm gas supply	671,675	228,820	1,013	--	--	--	901,508

The Company believes that all demand charges will be recoverable in rates charged to its customers. Further, pursuant to implementation of FERC Order No. 636, the Company has the right to resell or release to others any of its unutilized gas supply or transportation and storage capacity.

The Company does not anticipate any difficulty in achieving the minimum annual take obligations shown, as such volumes represent approximately 64% of expected annual sales for 2003 and less than 11% of expected sales in subsequent years.

The Company's current firm gas supply contracts obligate the suppliers to provide, in the aggregate, annual volumes up to those shown below:

Maximum Supply Available under Current Firm Supply Contracts

(Therms in thousands)	2003	2004	2005	2006	2007	2008 & There-after	Total
Firm gas supply	719,821	264,035	7,013	6,000	6,000	24,000	1,026,869

Service Contract

On August 30, 2001, PSE and Alliance Data Systems Corp. announced a contract under which Alliance Data will provide data processing and billing services for PSE. In providing services to PSE under the 10-year agreement, Alliance Data will use ConsumerLinX software, PSE’s customer-information software developed by its ConneXt subsidiary. Alliance Data acquired the assets of ConneXt, including the exclusive use of the ConsumerLinX software for five years with an option for renewal. Alliance Data will offer ConsumerLinX as part of its integrated, single-source customer relationship management solution for large-scale, regulated utility clients. The obligations under the contract are $19.4 million in 2003, $20.0 million in 2004, $22.5 million in 2005, $23.2 million in 2006, $23.9 million in 2007 and $86.7 million in the aggregate thereafter.

Surety Bond

The Company has a self-insurance surety bond in the amount of $5.2 million guaranteeing compliance with the Industrial Insurance Act (workers' compensation) and nine self-insurer's pension bonds totaling $1.4 million.

Environmental

The Company is subject to environmental regulation by federal, state and local authorities. The Company has been named by the Environmental Protection Agency (EPA) and/or the Washington State Department of Ecology as potentially responsible at several contaminated sites and manufactured gas plant sites. PSE has implemented an ongoing program to test, replace and remediate certain underground storage tanks as required by federal and state laws and this process is nearing completion. Remediation and testing of

Company vehicle service facilities and storage yards is also continuing.

During 1992, the Washington Commission issued orders regarding the treatment of costs incurred by the Company for certain sites under its environmental remediation program. The orders authorize the Company to accumulate and defer prudently incurred cleanup costs paid to third parties for recovery in rates established in future rate proceedings. The Company believes a significant portion of its past and future environmental remediation costs are recoverable from either insurance companies, third parties or under the Washington Commission's order.

The information presented here as it relates to estimates of future liability is as of December 31, 2002.

Electric Sites

The Company has expended approximately $17.7 million related to the remediation activities covered by the Washington Commission's order and has accrued approximately $1.7 million as a liability for future remediation costs for these and other remediation activities. To date, the Company has recovered approximately $17.2 million from insurance carriers.

Based on all known facts and analyses, the Company believes it is not likely that the identified environmental liabilities will result in a material adverse impact on the Company's financial position, operating results or cash flow trends.

Gas Sites

The Company has expended approximately $62.5 million related to the remediation activities covered by a Washington Commission's order and has accrued approximately $33.3 million for future remediation costs for these and other remediation sites. To date, the Company has recovered approximately $58.7 million from insurance carriers and other third parties. The Company expects to recover legal and remediation activities from either insurance companies or customers per Washington Commission orders.

Based on all known facts and analyses, the Company believes it is not likely that the identified environmental liabilities will result in a material adverse impact on the Company's financial position, operating results or cash flow trends.

Litigation

Other contingencies, arising out of the normal course of the Company's business, exist at December 31, 2002. The ultimate resolution of these issues is not expected to have a material adverse impact on the financial condition, results of operations or liquidity of the Company.

NOTE 16.

Accounting for Derivative Instruments and Hedging Activities

On January 1, 2001, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by SFAS No. 138. SFAS No. 133 requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value. The Company enters into both physical and financial contracts to manage its energy resource portfolio including forward physical and financial contracts, option contracts and swaps. The majority of these contracts qualify for the normal purchase and normal sale exception provided by SFAS No. 133.

On January 1, 2001, the Company recognized the cumulative effect of adopting SFAS No. 133 by recording a liability and an offsetting after-tax decrease to current earnings of approximately $14.7 million for the fair value of electric derivatives that did not meet hedge criteria. The Company also recorded an asset and an offsetting increase to other comprehensive income of approximately $286.9 million for the fair value of derivative instruments that did meet hedge criteria on the implementation date.

During the year ended December 31, 2001, the Company recorded an increase to current earnings of approximately $11.2 million pre-tax ($7.2 million after-tax) to record the change in market value of outstanding derivative instruments not meeting cash flow hedge criteria. During the year ended December 31, 2002, the remainder of the contracts which had given rise to the income statement losses were settled and resulted in an additional increase to earnings of $11.6 million pre-tax ($7.5 million after-tax). As of

December 31, 2002, the Company had a long-term unrealized gain recorded in Other Comprehensive Income of $9.9 million after-tax and a short term unrealized loss of $2.4 million after-tax related to contracts which meet the criteria for designation as cash flow hedges under SFAS No. 133. The amount of cash flow hedges that will reverse and be settled into the income statement during 2003 will be $4.1 million. In addition, on December 31, 2002 the Company had a short term unrealized gain on derivative contracts for the purchase of natural gas for core gas business of $3.7 million pre-tax.

The Company has two contracts outstanding with a counterparty whose senior unsecured debt ratings were downgraded in September 2002 to Ba2 by Moody's and in November 2002 to BB by Standard & Poor's. The first contract is a fixed for floating price natural gas swap contract for which the Company has collected a collateral deposit in the amount of $21.4 million from the counterparty to guarantee performance. The contract will expire in June 2008 and is accounted for as a cash flow hedge under SFAS No. 133. The second is a physical gas supply contract expiring in July 2008 which has been designated as a normal purchase under SFAS No. 133. In February 2003, the counterparty's credit was further downgraded although the counterparty continues to perform as required under the terms of the two contracts. The Company believes the risk of non-performance by the counterparty is remote.

At October 15, 2001, the Company had recorded a deferred liability of approximately $26.9 million after-tax for financial gas contracts to be used for electric production that until October 15, 2001 were designated as qualifying cash flow hedges. Changes in the market values of these de-designated contracts resulted in the recording of a loss of $7.8 million pre-tax ($5.1 million after-tax) to earnings in the fourth quarter of 2001. In the first quarter of 2002, the loss was reversed in its entirety when all of these contracts were settled or terminated.

During 2001, the Financial Accounting Standards Board's Derivative Implementation Group for SFAS No. 133 issued guidance under Issue C16 – "Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract" which became effective in the second quarter of 2002 for the Company. Issue C16 establishes that fuel supply contracts that combine a forward contract with a purchased option cannot qualify for the normal purchase and normal sales exception because of the optionality of the quantity of fuel to be delivered under the contract.

A review of the fuel supply contracts by the Company determined that two long-term fuel supply contracts that deliver natural gas to the Company's Encogen combustion turbine plant contained provisions for the purchase of optional quantities of fuel, and as originally written, would no longer qualify as normal purchase contracts upon implementation of Issue C16. In the second quarter of 2002, the Company signed amendments to those contracts that remove the optional provisions, requiring that the Company purchase 100% of the contractual fuel quantities for the remaining terms of the contracts. As a result, the contracts continue to qualify for the normal purchase-normal sale exception to SFAS 133.

NOTE 17.

Supplemental Quarterly Financial Data (Unaudited)

The following unaudited amounts, in the opinion of the Company, include all adjustments (consisting of normal recurring adjustments) necessary for a fair presentation of the results of operations for the interim periods. Quarterly amounts vary during the year due to the seasonal nature of the utility business.

(Unaudited; dollars in thousands)

2002 Quarter	First	Second	Third	Fourth
Operating revenues	$678,299	$464,697	$366,103	$563,694
Operating income	74,732	72,724	51,367	95,769
Other income	309	3,455	210	1,241
Net income	25,698	28,839	4,701	49,709

(Unaudited; dollars in thousands)

2001 Quarter	First	Second	Third	Fourth

Operating revenues	$995,694	$664,827	$426,195	$628,058
Operating income	130,111	61,629	42,360	54,383
Other income	2,843	2,485	8,885	2,839
Net income	72,879	17,275	5,474	8,754

Operating revenues for the Company include optimization transactions reported net in the income statement as required by EITF 02-03 effective after June 30, 2002. The operating revenues for all quarters of 2001 and the first and second quarters of 2002 have been reclassified to conform with the current presentation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

1. Report in columns (b) (c) 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.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceeding Year	4,750,309			
2	Preceding yr. Reclassification from Account 219 Net Income	(5,000)			
3	Preceding Year Changes in Fair Value	(1,823,203)	(5,148,177)		
4	Total (lines 2 and 3)	(1,828,203)	(5,148,177)		
5	Balance of Account 219 at End of Preceding Yr/Beginning of Current Yr	2,922,106	(5,148,177)		
6	Current Year Reclassification From Account 219 to Net Income				
7	Current Year Changes in Fair Value	(1,358,711)	(2,097,823)		
8	Total (lines 6 and 7)	(1,358,711)	(2,097,823)		
9	Balance of Account 219 at End of Current Year	1,563,395	(7,246,000)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

Line No.	Other Cash Flow Hedges Energy Contracts (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 72) (i)	Total Comprehensive Income (j)
1			4,750,309		
2			(5,000)		
3	(27,094,500)		(34,065,880)		
4	(27,094,500)		(34,070,880)	104,381,271	70,310,391
5	(27,094,500)		(29,320,571)		
6	31,701,470		31,701,470		
7	2,852,828		(603,706)		
8	34,554,298		31,097,764	108,947,246	140,045,010
9	7,459,798		1,777,193		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

Line No.	Classification (a)	Total (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	6,055,243,679	4,063,562,074
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	6,055,243,679	4,063,562,074
9	Leased to Others		
10	Held for Future Use	8,729,486	7,002,577
11	Construction Work in Progress	108,658,275	80,916,599
12	Acquisition Adjustments	78,188,137	77,871,127
13	Total Utility Plant (8 thru 12)	6,250,819,577	4,229,352,377
14	Accum Prov for Depr, Amort, & Depl	2,337,832,036	1,732,938,202
15	Net Utility Plant (13 less 14)	3,912,987,541	2,496,414,175
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,207,471,378	1,693,602,751
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	105,071,782	14,363,585
22	Total In Service (18 thru 21)	2,312,543,160	1,707,966,336
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	222,339	222,339
29	Amortization		
30	Total Held for Future Use (28 & 29)	222,339	222,339
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	25,066,537	24,749,527
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,337,832,036	1,732,938,202

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
1,618,020,331				373,661,274	3
					4
					5
					6
					7
1,618,020,331				373,661,274	8
					9
1,726,909					10
22,559,302				5,182,374	11
317,010					12
1,642,623,552				378,843,648	13
497,099,971				107,793,863	14
1,145,523,581				271,049,785	15
					16
					17
484,091,312				29,777,315	18
					19
					20
12,691,649				78,016,548	21
496,782,961				107,793,863	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
317,010					32
497,099,971				107,793,863	33

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Show in a footnote the account 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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	114,202	
3	(302) Franchises and Consents	686,442	68,667
4	(303) Miscellaneous Intangible Plant	24,596,251	525,098
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	25,396,895	593,765
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	3,565,645	
9	(311) Structures and Improvements	172,167,873	
10	(312) Boiler Plant Equipment	379,459,353	9,538,529
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	111,262,841	
13	(315) Accessory Electric Equipment	35,482,109	
14	(316) Misc. Power Plant Equipment	13,685,760	
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	715,623,581	9,538,529
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights		
18	(321) Structures and Improvements		
19	(322) Reactor Plant Equipment		
20	(323) Turbogenerator Units		
21	(324) Accessory Electric Equipment		
22	(325) Misc. Power Plant Equipment		
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)		
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights	12,346,045	
26	(331) Structures and Improvements	15,497,481	237,134
27	(332) Reservoirs, Dams, and Waterways	142,045,634	1,685,260
28	(333) Water Wheels, Turbines, and Generators	29,940,386	116,930
29	(334) Accessory Electric Equipment	7,871,747	39,863
30	(335) Misc. Power PLant Equipment	3,913,353	67,865
31	(336) Roads, Railroads, and Bridges	1,972,147	
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	213,586,793	2,147,052
33	D. Other Production Plant		
34	(340) Land and Land Rights	3,837,051	
35	(341) Structures and Improvements	12,084,603	38,245
36	(342) Fuel Holders, Products, and Accessories	15,387,399	
37	(343) Prime Movers		
38	(344) Generators	138,144,330	43,090
39	(345) Accessory Electric Equipment	3,791,450	29,644

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
40	(346) Misc. Power Plant Equipment	2,256,073	12,005
41	TOTAL Other Prod. Plant (Enter Total of lines 34 thru 40)	175,500,906	122,984
42	TOTAL Prod. Plant (Enter Total of lines 15, 23, 32, and 41)	1,104,711,280	11,808,565
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	8,067,699	
45	(352) Structures and Improvements	2,283,527	123,031
46	(353) Station Equipment	75,427,094	251,163
47	(354) Towers and Fixtures	67,682,798	
48	(355) Poles and Fixtures	24,287,844	118,908
49	(356) Overhead Conductors and Devices	96,926,631	21,739
50	(357) Underground Conduit	34,382	
51	(358) Underground Conductors and Devices	400	
52	(359) Roads and Trails	606,197	
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	275,316,572	514,841
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights	40,632,664	98,706
56	(361) Structures and Improvements	5,716,376	
57	(362) Station Equipment	305,279,230	12,059,302
58	(363) Storage Battery Equipment		
59	(364) Poles, Towers, and Fixtures	301,192,379	11,531,067
60	(365) Overhead Conductors and Devices	330,996,819	7,428,474
61	(366) Underground Conduit	386,677,814	23,487,517
62	(367) Underground Conductors and Devices	433,232,973	26,059,160
63	(368) Line Transformers	302,918,344	9,405,726
64	(369) Services	165,356,454	3,398,140
65	(370) Meters	111,272,796	6,090,102
66	(371) Installations on Customer Premises		
67	(372) Leased Property on Customer Premises	2,897,629	
68	(373) Street Lighting and Signal Systems	32,896,992	708,080
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	2,419,070,470	100,266,274
70	5. GENERAL PLANT		
71	(389) Land and Land Rights	4,834,676	
72	(390) Structures and Improvements	30,044,837	229,917
73	(391) Office Furniture and Equipment	50,470,646	151,673
74	(392) Transportation Equipment	7,100,244	
75	(393) Stores Equipment	2,274,818	
76	(394) Tools, Shop and Garage Equipment	7,367,057	130,384
77	(395) Laboratory Equipment	10,882,127	295,411
78	(396) Power Operated Equipment	13,296,575	
79	(397) Communication Equipment	40,896,463	618,446
80	(398) Miscellaneous Equipment	460,567	
81	SUBTOTAL (Enter Total of lines 71 thru 80)	167,628,010	1,425,831
82	(399) Other Tangible Property		
83	TOTAL General Plant (Enter Total of lines 81 and 82)	167,628,010	1,425,831
84	TOTAL (Accounts 101 and 106)	3,992,123,227	114,609,276
85	(102) Electric Plant Purchased (See Instr. 8)		
86	(Less) (102) Electric Plant Sold (See Instr. 8)		
87	(103) Experimental Plant Unclassified		
88	TOTAL Electric Plant in Service (Enter Total of lines 84 thru 87)	3,992,123,227	114,609,276

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

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.

6. 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.

7. 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.

8. 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 of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			114,202		2
10,387			744,722		3
5,431,635			19,689,714		4
5,442,022			20,548,638		5
					6
					7
181			3,565,464		8
313,331			171,854,542		9
421,807			388,576,075		10
					11
37,570			111,225,271		12
			35,482,109		13
253,884			13,431,876		14
1,026,773			724,135,337		15
					16
					17
					18
					19
					20
					21
					22
					23
					24
		-107	12,345,938		25
139,433			15,595,182		26
41,584		19,992	143,709,302		27
			30,057,316		28
978			7,910,632		29
			3,981,218		30
			1,972,147		31
181,995		19,885	215,571,735		32
					33
		-6,900	3,830,151		34
			12,122,848		35
			15,387,399		36
					37
1,540,295			136,647,125		38
43,314			3,777,780		39

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
			2,268,078		40
1,583,609		-6,900	174,033,381		41
2,792,377		12,985	1,113,740,453		42
					43
		-404,916	7,662,783		44
			2,406,558		45
		-571,376	75,106,881		46
			67,682,798		47
-6,551		-28,778	24,384,525		48
-4,831		-15,612	96,937,589		49
			34,382		50
		-61	339		51
			606,197		52
-11,382		-1,020,743	274,822,052		53
					54
		441,615	41,172,985		55
9,971		6,994	5,713,399		56
2,166,151		567,504	315,739,885		57
					58
1,602,782		28,778	311,149,442		59
2,856,339		-6,168,611	329,400,343		60
451,464			409,713,867		61
3,707,798		-19,046	455,565,289		62
1,295,023		-3,122	311,025,925		63
1,182,343			167,572,251		64
6,149,806		6,203,329	117,416,421		65
					66
744,698			2,152,931		67
386,981			33,218,091		68
20,553,356		1,057,441	2,499,840,829		69
					70
			4,834,676		71
			30,274,754		72
2,348,900			48,273,419		73
1,743,853			5,356,391		74
641,282			1,633,536		75
35,122			7,462,319		76
36,678			11,140,860		77
8,099,615			5,196,960		78
1,555,814		24,050	39,983,145		79
6,528			454,039		80
14,467,792		24,050	154,610,099		81
					82
14,467,792		24,050	154,610,099		83
43,244,165		73,733	4,063,562,071		84
					85
					86
					87
43,244,165		73,733	4,063,562,071		88

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
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10					
11					
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14					
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41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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	Land and Land Rights:			
3	Clyde Hill Substation	11/95	12/06	397,742
4	Colby Substation	12/86	12/08	266,926
5	Lochleven Substation	03/87	12/05	345,710
6	Plateau Substation (formerly Maple Lake)	12/98	12/06	375,086
7	BPA Kitsap - Bangor R/W	7/90	12/09	868,381
8	Christopher Weyerhauser	02/00	12/10	378,124
9	Novelty - Cottage Brook	10/99	12/05	495,140
10	Talbot - Lakeside	02/00	12/10	274,461
11	Mt. Si Substation	12/01	12/10	496,882
12	Novelty Hill	12/98	12/05	380,771
13	Westminster Switching Station	12/91	12/10	1,630,427
14				
15	Land and Land Rights under $250,000:			
16	Transmission Land Sites - 15			976,833
17	Distribution Land Sites - 3			116,094
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
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32				
33				
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35				
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42				
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44				
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46				
47	Total			7,002,577

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	116 AVE SE & SE 223 ST	1,109,837
2	208 AVE NE & NE 85 ST	177,559
3	180TH ST TO 256TH TO SR 18	464,935
4	NOVELTY HILL RD/212 TO 2	121,206
5	SERWOLD SUBSTATION	110,686
6	ENGINEERING & PROJECT DEVE	174,721
7	FOURTH & WATER OLYMPIA	139,739
8	SR99 S312-324 ST FED WY	474,268
9	SR99 S312-324 ST FED WY	343,148
10	SR99 CONVERSION PHASE 1	111,806
11	VALENCIA 22 UG CONV	591,699
12	ENGINEERING & DEVELOPMENT	252,697
13	SR99/216TH TO KENT-DES	138,903
14	140 AVE SE - PETROVISKY	145,227
15	SOUND TRANSIT KENT STAT	121,814
16	SR99 CONVERSION, KENT P	115,808
17	NRU/27 FEEDER UPGRADE1	251,150
18	RJN 35 WORK AT 72ND/S	131,999
19	LOCHLEVEN SUB-DISTR	241,382
20	NORTHSPAR RELOC-DISTR	248,508
21	NORTHSPAR REL-FUTURE FA	313,397
22	INTERNATIONAL BLVD#3 UG	469,722
23	PLUM CKTS REBLD, DNTOWN	506,760
24	AMES LK TAP REL-QUADRNT	100,943
25	GRAVELLY LK SUB EXPANSI	327,433
26	GRAVELLY LK SUB EXP-PRE	242,915
27	SPU SUB-LK YOUNGS WTRSH	318,094
28	GRANDRIDGE SUBSTATION-P	113,349
29	WATER STREET IMPROVEMENT	172,936
30	CENTER #12 116 AVE COND	235,141
31	CENTER #13 116 AVE COND	186,873
32	CENTER N-1 116 AVE COND	190,930
33	116 AVE CBD GROWTH-CON	191,510
34	SE 24 TO SE 30 ON 247 AVE	198,430
35	C ST SW, AUBURN (CAP)	131,184
36	LK. TAPPS PWKY. E. FEEDER	162,553
37	SOOS CREEK 205E 103 INSTALL XFR 141	386,529
38	WHITE RIVER DIVERSION DAM	1,778,970
39	WHITE RIVER GENERATING STA	236,368
40	WHITE RIVER PROJECT PART 1	1,018,271
41	BAKER RELICENSE	3,781,197
42	WHITE RIVER LICENSE	14,330,985
43	TOTAL	80,916,599

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	SNOQUALMIE RELICENSE	11,984,456
2	EAP WARNING SYSTEM - WHR	137,985
3	LBK FISH BARGE ENGINEERIN	204,077
4	WATERLINE FROM LODGE-UBK	164,655
5	FSH PSSG-DESIGN MTGS ADMIN	460,295
6	AQUATIC STUDIES - LBK/UBK	107,410
7	ECON.OPS STUDIES RELICENS.	248,572
8	TERREST. PROJ MGMT-BAK LIC	233,633
9	REC. PROJ. MGMT.-BAK LICEN	253,490
10	AQUATIC PROJ.MGMT.BAK LICE	314,957
11	ADMIN.MTG.FACIL.BAK RELICE	346,023
12	ADMIN.DOCUMENT RM.BAK RELI	136,120
13	CULT.ARCH.INVENTORY-BAK LI	219,047
14	CULTURAL PROJ. MGMT.BAK LIC	103,930
15	GIS & GPS BAKER RELICENSIN	175,081
16	RELCNSE_REC_VISITOR SURVEY	228,977
17	RELICENSE-TERREST.VEG.MAPS	283,519
18	RELCNS.TEREST.AMPHIB.STDIE	170,265
19	RLCNS.TRRST.WLDLF.STDIES-	110,095
20	SKAGIT R.FLOW,RAMPING & HA	382,626
21	RESERVOIR TRIBUTARY HABITA	124,015
22	DEPT.OF ECOLOGY WATER RIGHT	1,604,439
23	WATER INJECT.SYST.BETTERMT	1,029,087
24	BAK RELICENS UPSTREAM PSSG	213,186
25	BAK RELICENSE DNSTRM FISH	593,553
26	BAK RELICENSE DNSTRM FISH	310,830
27	SNOQUALMIE RELICENSE ENGINEERING	142,021
28	ELECTRON BENT INSTALLATION	211,278
29	FISH TRAP TIE-OFF INSTALLATION-UBK	157,169
30	PARK DR & NORTH SPAR RD	510,048
31	201 AVE SE/SE 78 ST ISSAQU	525,498
32	2400 PARK DR ISSAQUAH	173,016
33	MAP-VAL BLK-DIA RD GLACIER	138,722
34	5800 ROAD 5 ISSAUQUAH	138,235
35	13200 TRILOGY PKWY NE REDM	104,403
36	NE 104 ST AND 252 AVE NE NO	3,165,170
37	NOVELTY - COTTAGE 115 KV L	407,525
38	NOVELTY - SNOQ 115KV LINE	421,087
39	NOVELTY - SAMM 115 LINE	462,365
40	NOVELTY - LAKE TRADITION 1	374,576
41	SOUTH BREMERTON TO VALLEY	170,041
42	WEST KITSAP TRANS LINE/PRE CONST CH	200,768
43	TOTAL	80,916,599

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	PRE-CONST CHARGS HWY 2 & S LAK STVN	101,540
2	PTT LOOP NEW 115KV LINE: PRECONSTRU	195,308
3	WOODLAND-ST.CLAIR UPGRADE-TRANSM.CA	386,371
4	WOODLAND-ST.CLAIR UPGRADE-PRE CONST	330,599
5	OLYMPIA/ADD SEL PDN 1155	113,801
6	SR99 S312-324 ST FED WY	164,645
7	140 AVE SE - PETROVITSKY	133,975
8	PICKERING-LK TRAD PH2 P	283,231
9	ST CLAIR SUB 115KV BAY	296,287
10	COB SE 38TH ST RELOCATE TR	301,768
11	BAKER RIVER SWITCH/55KV	326,280
12	BAKER RIVER SWITCH/55KV	302,055
13	PLU ADD THIRD ZONE RELA	108,949
14	NOVELTY-SNOQUALMIE	193,711
15	ELECTRIC EMS UPGRADE - SOFTWARE	1,302,447
16	NOVELTY HILL PROJECT LAND PURCH/KOC	635,713
17	HAWKS PRAIRIE SUBSTATION LAND PURCH	115,197
18		
19	MISC CONSTRUCTION WORK IN PROGRESS - DISTRIBUTION PLANT	8,480,075
20	MISC CONSTRUCTION WORK IN PROGRESS - GENERATION PLANT	1,460,484
21	MISC CONSTRUCTION WORK IN PROGRESS - NEW BUSINESS PLANT	3,413,957
22	MISC CONSTRUCTION WORK IN PROGRESS - TRANSMISSION PLANT	3,396,740
23	MISC CONSTRUCTION WORK IN PROGRESS - GENERAL PLANT	331,452
24		
25	S/P ACCRUAL - ELECTRIC	238,187
26		
27		
28		
29		
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31		
32		
33		
34		
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36		
37		
38		
39		
40		
41		
42		
43	TOTAL	80,916,599

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,616,807,790	1,616,162,108	645,682	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	115,740,234	115,740,234		
4	(413) Exp. of Elec. Plt. Leas. to Others				
5	Transportation Expenses-Clearing	6,775	6,775		
6	Other Clearing Accounts	364,466	364,466		
7	Other Accounts (Specify, details in footnote):				
8					
9	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 8)	116,111,475	116,111,475		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	22,078,424	22,078,424		
12	Cost of Removal	16,945,527	16,945,527		
13	Salvage (Credit)				
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	39,023,951	39,023,951		
15	Other Debit or Cr. Items (Describe, details in footnote):	-70,224	353,119	-423,343	
16					
17	Balance End of Year (Enter Totals of lines 1, 9, 14, 15, and 16)	1,693,825,090	1,693,602,751	222,339	
	Section B. Balances at End of Year According to Functional Classification				
18	Steam Production	377,775,136	377,775,136		
19	Nuclear Production				
20	Hydraulic Production-Conventional	99,175,170	99,175,170		
21	Hydraulic Production-Pumped Storage				
22	Other Production	95,905,372	95,905,372		
23	Transmission	99,341,625	99,119,286	222,339	
24	Distribution	946,178,027	946,178,027		
25	General	75,449,760	75,449,760		
26	TOTAL (Enter Total of lines 18 thru 25)	1,693,825,090	1,693,602,751	222,339	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	PUGET WESTERN INC	05/31/60		
2	Common			10,200
3	Equity			101,068,622
4	Add Paid in Capital			-8,492,874
5	Other Investments			1,632,256
6	Subtotal			94,218,204
7				
8	HYDRO ENERGY DEVELOPMENT CORP	11/30/88		
9	Common			1,500
10	Equity			-17,359,885
11	Add Paid in Capital			-7,776,372
12	Advances - Open Account			27,786,896
13	Advances - Interest			3,156,678
14	Interest Receivable			8,556,189
15	Subtotal			14,365,006
16				
17	CONNEXT	01/05/96		
18	Preferred			3,500,000
19	Common			500
20	Equity			-17,736,098
21	Add Paid in Capital			2,065,038
22	Advances - Open Account			18,716,668
23	Interest Receivable			966,304
24	Subtotal			7,512,412
25				
26	WEGM	03/02/94		
27	Add Paid in Capital			25,624,255
28	Equity			-25,682,548
29	Subtotal			-58,293
30				
31	PSE SECURITY ASSETS, INC. (formerly Homeguard)	10/01/93		
32	Add Paid in Capital			-8,915,381
33	Equity			8,915,753
34	Subtotal			372
35				
36	PUGET SOUND ENERGY SERVICES, INC.	12/17/97		
37	Add Paid in Capital			1,849,641
38	Equity			-1,183,984
39	Subtotal			665,657
40				
41				
42	Total Cost of Account 123.1 $ 124,345,549		TOTAL	116,975,228

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	PUGET SOUND ENERGY UTILITY SOLUTIONS, INC.	04/08/99		
2	Equity			-45,590
3	Add Paid in Capital			73,710
4	Advance			241,750
5	Subtotal			269,870
6				
7	GP ACQUISITION CORP.	09/21/99		
8	Add Paid in Capital			1,000
9	Subtotal			1,000
10				
11	LP ACQUISITION CORP.	09/21/99		
12	Add Paid in Capital			1,000
13	Subtotal			1,000
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
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26				
27				
28				
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32				
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35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 124,345,549		TOTAL	116,975,228

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		10,200		2
5,217,482		106,286,104		3
	-389,385	-8,882,259		4
	17,699,947	19,332,203		5
5,217,482	17,310,562	116,746,248		6
				7
				8
		1,500		9
-252,713		-17,612,598		10
	-6,708,787	-14,485,159		11
	-50,000	27,736,896		12
		3,156,678		13
		8,556,189		14
-252,713	-6,758,787	7,353,506		15
				16
				17
		3,500,000		18
		500		19
79,865		-17,656,233		20
	-7,592,277	-5,527,239		21
		18,716,668		22
		966,304		23
79,865	-7,592,277			24
				25
				26
	-31,935	25,592,320		27
		-25,682,548		28
	-31,935	-90,228		29
				30
				31
		-8,915,381		32
	-372	8,915,381		33
	-372			34
				35
				36
	-189,198	1,660,443		37
-141,599		-1,325,583		38
-141,599	-189,198	334,860		39
				40
				41
4,903,035	2,467,286	124,345,549		42

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		-45,590		2
	-270,707	-196,997		3
		241,750		4
	-270,707	-837		5
				6
				7
		1,000		8
		1,000		9
				10
				11
		1,000		12
		1,000		13
				14
				15
				16
				17
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				40
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4,903,035	2,467,286	124,345,549		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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)	11,960,566	11,980,471	Electric & Gas
2	Fuel Stock Expenses Undistributed (Account 152)			Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	20,457,206	19,489,725	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	3,891,549	3,801,759	Electric & Gas
8	Transmission Plant (Estimated)	154,522	156,325	Electric & Gas
9	Distribution Plant (Estimated)	1,345,436	1,332,564	Electric & Gas
10	Assigned to - Other (provide details in footnote)	463,884	475,487	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	26,312,597	25,255,860	
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
15	Stores Expense Undistributed (Account 163)	1,357,293	1,350,654	Electric & Gas
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	39,630,456	38,586,985	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

Allowances (Accounts 158.1 and 158.2)

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

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year		2003	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2004		2005		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
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								45
								46

Schedule Page: 228 Line No.: 1 Column: l

The Environmental Protection Agency (EPA) has made an allocation of the following allowances to Puget Sound Energy. No dollar amounts have been assigned to these allowances on the books and records of Puget Sound Energy, Inc. The activity during 2002 is as follows:

Year	PSE Balance At 12/31/01	Transfer To Mirant Corp.	Transfer To PP&L Montana	Transfer From PP&L Montana	2002 Colstrip 1-4 Obligation	PSE Balance At 12/31/02
1998	24				(7)	17
2000	3,132		(3,132)			0
2001	9,442		(9,442)			0
2002	6,635		(3,000)			3,635
2003	6,836					6,836
2004	6,835					6,835
2005-2032	224,486			3,686		228,172
	257,390	0	(15,574)	3,686	(7)	245,495

Schedule Page: 228 Line No.: 29 Column: m

Same as footnote above for page 228, line 1, column l.

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

The following table reflects 2002 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. However, there were no sales in 2002.

Plant	1/1/02 Estimated Balance of Withheld Allowances Years 2009-2025	EPA Estimated Balance of Withheld Allowances Years 2008-2009	12/31/02 Estimated Balance of Withheld Allowances Years 2009-2025
Colstrip Unit 1	3,782	0	3,782
Colstrip Unit 2	3,748	0	3,748
Colstrip Unit 3	1,888	0	1,888
Colstrip Unit 4	2,592	0	2,592

Puget Sound Energy owns or controls 50% of Colstrip Units 1 & 2, and 25% of Colstrip Units 3 & 4, and therefore owns the same percentages of the estimated allowances listed above.

Schedule Page: 228 Line No.: 40 Column: m

Same as footnote above for page 228, line 36, column l.

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

There were no sales proceeds in 2002 from sales of allowances withheld by the Environmental Protection Agency.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	Storm Damages			407	4,750,002	21,851,678
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL				4,750,002	21,851,678

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	NONE					
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
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46						
47						
48						
49	TOTAL					

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

Includes ($690,362) annual adjustment for the contract year 2001-2002

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the rate making actions of regulatory agencies (and not includable in other accounts)
2. For regulatory assets being amortized, show period of amortization in column (a)
3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	CREDITS Account Charged (c)	CREDITS Amount (d)	Balance at End of Year (e)
1	Unamortized conservation Costs- 1 to 10 years	32,273,086	Various	39,101,350	7,984,985
2	Adv Pmt Rock Island chelan PUD - 48 years	5,209	555	41,667	31,249
3	Deferred AFUDC	2,550,689	406	1,104,404	29,925,733
4	Colstrip Common - 37.5 years		406	715,282	15,347,566
5	BPA Power Exchange - 30.5 years		555	3,526,620	51,135,898
6	SFAS 106 Post Ret Benefits		926	222,000	2,220,056
7					
8					
9					
10	Regulatory Tax Asset		283	25,958,000	167,058,010
11					
12					
13	Environmental Remediation Costs	1,546,443	407	274,128	4,499,440
14	PURPA Buyout Regulatory Asset - 14 years	8,792,530	555	9,503,625	230,959,663
15	PURPA Buyout Regulatory Asset - 8.5 years	731,000	Various	1,070,000	12,624,783
16	Tree Watch Program - 10 years	6,194,431	Various	3,108,733	26,506,377
17	Gas Rental Equipment Pipe & Vent	603,486		167,834	1,709,735
18	2001 Rate Case	6,414,040		4,055,610	4,757,878
19	Low Income Program	684,947		684,947	
20	Electric Gross PCA	29,217,652		29,217,652	
21	Deferred Energy Costs - UE-11600	242,416,265		242,416,265	
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
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35					
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38					
39					
40					
41					
42					
43					
44	TOTAL	331,429,778		361,168,117	554,761,373

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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 $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits	Balance at Beginning of Year	Debits	CREDITS		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	FASB 87 Pension costs	17,988,891	2,478,824	253	9,912,715	10,555,000
2	PSD Pension Csts Excess Cntrib	53,824,889	23,908,218	926	4,372,323	73,360,784
3	AFUCE Gross Up	349,745	80	421	183,970	165,855
4	Clearing Acct Charges	145,373	323,736	184	150,667	318,442
5	Adv. Pay Montana Firm Cntrct	459,199		555	51,022	408,177
6	Environmental Remediation Exp.	19,824,206	35,167,363	Various	17,929,145	37,062,424
7	Non-temp facilities	1,283,966	2,577,312	Various	2,946,232	915,046
8	Non-temp facilities - common	881,986	5,410,680	Various	5,994,220	298,446
9	Damage Claims	1,329,286	8,114,969	Various	8,381,704	1,062,551
10	Municipal Audit Assessments	660,460				660,460
11	2000 Universal Shelf	76,606	166,022	181	242,628	
12	2002 Universal Shelf		259,614	Various	87,026	172,588
13	FAS 133 Net Unrealized Gn/(Ls)	-3,239,970	6,417,344	Various	6,814,769	-3,637,395
14	FAS 133 Unrealized Gain/(Loss)	3,239,970	2,867,243	Various	6,107,213	
15	CFS Parts Warranty Remibursemen		3,747	Various	81	3,666
16	Restricted Stock Grant		625,275	253	250,065	375,210
17	New Credit Agreement - 364 days		1,576,928			1,576,928
18						
19						
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45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	96,824,607				123,298,182

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	CIAC	30,557,777	38,104,777
3			
4	Pension Liability	-16,028,000	-20,763,000
5	Pension - Enhanced Sepatation	1,259,000	1,259,000
6	Vacation Pay	3,071,000	2,522,000
7	Other	54,540,966	50,713,353
8	TOTAL Electric (Enter Total of lines 2 thru 7)	73,400,743	71,836,130
9	Gas		
10	CIAC	3,119,000	4,298,000
11	Environmental	5,861,000	6,232,000
12	Pension/Vacation		
13	Merger Costs		
14	Demand Charges	7,170,000	8,776,000
15	Other	22,649,963	24,932,504
16	TOTAL Gas (Enter Total of lines 10 thru 15	38,799,963	44,238,504
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	112,200,706	116,074,634

Notes

Schedule Page: 234 Line No.: 2 Column: c

Line 2 - CIAC	Beginning Balance (Col b)	Credit to 411.1	Debit to 410.1	Account Number	Other DR (CR)	Ending Balance (Col c)
CIAC, Post 1-8-79	65,918		22,000			43,918
CIAC, 1986 Change	152,427		34,000			118,427
CIAC, 1987 Change	30,339,432	(14,025,000)	6,422,000			37,942,432
Total	30,557,777	(14,025,000)	6,478,000	-	-	38,104,777

Schedule Page: 234 Line No.: 7 Column: c

Line 7 - Other	Beginning Balance (Col b)	Credit to 411.1	Debit to 410.1	Account Number	Other DR (CR)	Ending Balance (Col c)
Land Sales	3,958,018	751,000				3,207,018
Cabot Gas Contract			834,860	190, 283	(3,706,000)	2,871,140
SERP's	2,032,316		52,802	411.2, 410.2, 190	1,424,550	554,964
Non-Quil. SRP- Officers	4,971,679	(5,000)	1,996,000	190	(588,254)	3,568,933
L/T Incentive Plan	388,359			411.2, 410.2, 190	383,991	4,368
Environmental Clean-up	49,000					49,000
Environmental Costs/fund site clean-up	(66,000)	214,000				(280,000)
SFAS 106 Operating	1,637,000	(494,000)				2,131,000
SFAS 106 Non-Operating	366,450			410.2	35,700	330,750
SFAS 106 Plan Curtailment Loss	455,000					455,000
Gain on Dis. of Emis Allowance	1,160,000		107,000			1,053,000
Deferred Compensation	3,469,000	(1,348,000)		190	(938,616)	5,755,616
Senior Mgmt LT Incentive Plan	2,630,759			411.2, 410.2, 190	326,078	2,304,681
Merger Costs	2,458,000					2,458,000
IRS Audit	2,968,104		3,272,669	283	(2,417,000)	2,112,435
Mark to Market	5,204,000			236	4,340,139	863,861
Deferred Stock Options	18,000		(1,000)			19,000
Gardiner Property Deferred Loss	159,437					159,437
Colstrip Reclamation	363,000	(476,000)				839,000
Employee Stock Grants - Electric	(7,000)					(7,000)
Deferred FAS 133	4,027,844	2,371,267	1,656,577			-
California ISO	12,777,000					12,777,000
California PX	1,044,000					1,044,000
Advance Payment	5,904,000		422,000			5,482,000
Deferred FIT Receivable - NOL	-	(9,856,039)	7,891,211	234	(256,322)	2,221,150
Repair Allowance - Electric	(1,750,000)			283	(1,750,000)	-
Encogen Activity - Electric	323,000		(416,000)			739,000
Total 190's	54,540,966	(8,842,772)	15,816,119		(3,145,734)	50,713,353

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	ACCOUNT 201			
2	COMMON STOCK (NYSE)	150,000,000	10.00	
3				
4	TOTAL COMMON	150,000,000	10.00	
5				
6				
7				
8	ACCOUNT 204			
9	PREFERRED STOCK			
10	$100 Par Value:			
11	4.70% Cumulative	150,000	100.00	101.00
12	4.84% Cumulative	150,000	100.00	102.00
13	7.75% Cumulative	750,000	100.00	102.58
14				
15	$25 Par Value			
16	7.45% Series II Cumulative (NYSE)	2,400,000	25.00	
17				
18				
19	Total Preferred	3,450,000		
20				
21	ACCOUNT 205			
22	8.231% Capital Securities			
23	8.400% Capital Securities			
24				
25				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
85,903,790	859,037,900					2
						3
85,903,790	859,037,900					4
						5
						6
						7
						8
						9
						10
4,311	431,100					11
14,808	1,480,800					12
412,500	41,250,000					13
						14
						15
2,400,000	60,000,000					16
						17
						18
2,831,619	103,161,900					19
						20
						21
	100,000,000					22
	200,000,000					23
						24
						25
						26
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						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

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

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

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

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

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

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations Received from Stockholder	
2		
3	Account 209 - Reduction in Par or Stated Value of Capital Stock	
4		
5	Account 210 - Gain on Resale or Cancellation of Reacq. Capital Stock	
6		
7	Account 211 - Miscellaneous Paid-in-Capital	29,761,143
8		
9		
10		
11		
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40	TOTAL	29,761,143

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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	Common Stock Expense	7,133,880
2		
3	Preferred Stock Expense:	
4	7.75% Series	786,587
5	Adjustable Rate Series B	
6	7.45% - Series II	1,650,849
7		
8		
9		
10		
11		
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19		
20		
21		
22	TOTAL	9,571,316

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221		
2			
3	First Mortgage Bonds MTN 8.14% Series A	25,000,000	207,952
4	First Mortgage Bonds MTN 7.75%	100,000,000	839,600
5	First Mortgage Bonds MTN 8.59% Series A	5,000,000	44,502
6	First Mortgage Bonds MTN 8.40% Series A	10,000,000	83,981
7	Forsyth Pollution Control Bonds 7.05% 1991A	27,500,000	780,408
8	Forsyth Pollution Control Bonds 7.25% 1991B	23,400,000	625,255
9	Forsyth Pollution Control Bonds 6.80%	87,500,000	2,018,916
10	Forsyth Pollution Control Bonds 5.875%	23,460,000	617,951
11	Medium Term Notes - 7.85%	30,000,000	
12	Medium Term Notes - 8.06%	46,000,000	351,408
13	Medium Term Notes - 7.07%	27,000,000	
14	Medium Term Notes - 7.15%	5,000,000	
15	Medium Term Notes - 7.625%	25,000,000	
16	Medium Term Notes - 7.70%	50,000,000	362,500
17			173,500 D
18	Medium Term Notes - 8.20%	30,000,000	255,000
19	Medium Term Notes - 7.02%	30,000,000	217,500
20	Medium Term Notes - 6.20%	3,000,000	21,750
21	Medium Term Notes - 6.40%	11,000,000	79,750
22	Medium Term Notes - 7.35%	55,000,000	467,735
23	Medium Term Notes - 7.80%	30,000,000	217,500
24	Medium Term Notes - 7.02%	300,000,000	3,020,891
25	Medium Term Notes - 6.74%	200,000,000	2,013,927
26	Medium Term Notes - 6.46%	150,000,000	1,089,295
27	Medium Term Notes - 7.00%	100,000,000	951,197
28	Medium Term Notes - 7.61%	25,000,000	182,279
29	Medium Term Notes - 7.96%	225,000,000	1,729,237
30	Medium Term Notes - 7.69%	260,000,000	1,865,627
31			
32	Medium Term Notes - 6.25%	40,000,000	226,299
33	TOTAL	2,520,860,000	28,889,660

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	Capital Trust I - 8.231%	100,000,000	1,310,950
3	Capital Trust II - 8.400%	200,000,000	6,760,058
4			
5	Subtotal	2,243,860,000	26,514,968
6			
7	Bonds assumed which were originally issued by Washington Natural Gas Company		
8			
9	First Mortgage Bonds 9.57% Series	25,000,000	138,955
10	Medium Term Notes Series A 7.53%	10,000,000	
11	Medium Term Notes Series A 7.91%	20,000,000	
12	Medium Term Notes Series B 6.24%	1,500,000	15,596
13	Medium Term Notes Series B 6.31%	5,000,000	51,986
14	Medium Term Notes Series B 6.23%	1,500,000	15,596
15	Medium Term Notes Series B 6.30%	20,000,000	207,944
16	Medium Term Notes Series B 6.10%	8,500,000	88,050
17	Medium Term Notes Series B 6.07%	10,000,000	103,588
18	Medium Term Notes Series C 6.92%	8,000,000	80,641
19	Medium Term Notes Series C 6.92%	3,000,000	30,240
20	Medium Term Notes Series C 6.93%	20,000,000	201,603
21	Medium Term Notes Series C 6.58%	10,000,000	62,500
22	Medium Term Notes Series C 7.02%	20,000,000	201,603
23	Medium Term Notes Series C 7.04%	5,000,000	50,401
24	Medium Term Notes Series B 6.53%	3,500,000	37,265
25	Medium Term Notes Series B 6.51%	1,000,000	10,647
26	Medium Term Notes Series C 6.61%	3,000,000	18,750
27	Medium Term Notes Series C 6.62%	5,000,000	31,250
28	Medium Term Notes Series C 7.12%	7,000,000	74,061
29	Medium Term Notes Series B 6.83%	3,000,000	34,853
30	Medium Term Notes Series B 6.90%	10,000,000	116,177
31	Medium Term Notes Series C 7.35%	10,000,000	113,301
32	Medium Term Notes Series C 7.36%	2,000,000	22,660
33	TOTAL	2,520,860,000	28,889,660

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Medium Term Notes Series A 8.40%	3,000,000	33,267
2	Medium Term Notes Series A 8.39%	7,000,000	77,622
3	Medium Term Notes Series A 8.25%	25,000,000	277,222
4	Medium Term Notes Series B 7.19%	13,000,000	151,414
5	Medium Term Notes Series C 7.15%	15,000,000	112,500
6	Medium Term Notes Series C 7.20%	2,000,000	15,000
7			
8	SUBTOTAL	277,000,000	2,374,692
9			
10	Account 222, Reacquired Bonds		
11			
12	Account 223, Notes Payable to Assoc. Companies		
13			
14	Account 224, Other Long Term Debt		
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	2,520,860,000	28,889,660

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
11/25/91	11/30/06	11/25/91	11/30/06	25,000,000	2,035,000	3
01/27/92	02/01/07	01/27/92	02/01/07	100,000,000	7,750,000	4
04/09/92	04/09/12	04/09/92	04/09/12	5,000,000	429,500	5
05/07/92	05/07/07	05/07/92	05/07/07	10,000,000	840,000	6
08/07/91	08/01/21	08/07/91	08/01/21	27,500,000	1,938,750	7
08/07/91	08/01/21	08/07/91	08/01/21	23,400,000	1,696,500	8
03/01/92	03/01/22	03/01/92	03/01/22	87,500,000	5,950,000	9
04/29/93	04/01/20	04/29/93	04/01/20	23,460,000	1,378,275	10
05/29/92	05/29/02	05/29/92	05/29/02		974,708	11
06/18/92	06/19/06	06/18/92	06/19/06	46,000,000	3,707,600	12
08/28/92	08/28/02	08/28/92	08/28/02		1,261,995	13
09/11/92	09/11/02	09/11/92	09/11/02		249,256	14
12/10/92	12/10/02	12/10/92	12/10/02		1,800,401	15
12/10/92	12/10/04	12/10/92	12/10/04	50,000,000	3,850,000	16
						17
12/21/92	12/21/12	12/21/92	12/21/12	30,000,000	2,460,000	18
02/09/93	02/10/03	02/09/93	02/10/03	30,000,000	2,106,000	19
11/29/93	12/01/03	11/29/93	12/01/03	3,000,000	186,000	20
11/29/93	12/02/03	11/29/93	12/02/03	11,000,000	704,000	21
02/01/94	02/01/24	02/01/94	02/01/24	55,000,000	4,042,500	22
05/27/94	05/27/04	05/27/94	05/27/04	30,000,000	2,340,000	23
12/22/97	12/01/27	12/22/97	12/01/27	300,000,000	21,060,000	24
06/15/98	06/15/18	06/15/98	06/15/18	200,000,000	13,480,000	25
03/09/99	03/09/09	03/09/99	03/09/09	150,000,000	9,696,512	26
03/09/99	03/09/29	03/09/99	03/09/29	100,000,000	7,000,000	27
09/08/00	09/08/08	09/08/00	09/08/08	25,000,000	1,902,500	28
02/22/00	02/22/10	02/22/00	02/22/10	225,000,000	17,910,000	29
11/09/00	02/01/11	11/09/00	02/01/11	260,000,000	19,994,000	30
						31
01/16/02	01/16/04	01/16/02	01/16/04	40,000,000	2,402,778	32
				2,093,860,000	182,204,172	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
06/05/97	06/01/27	06/05/97	06/01/27		8,231,000	2
6/30/01	6/30/41	6/30/01	6/30/41		16,800,000	3
						4
				1,856,860,000	164,177,275	5
						6
						7
						8
09/01/90	09/01/20	09/01/90	09/01/20	25,000,000	2,392,500	9
01/09/92	01/09/02	01/09/92	01/09/02		18,825	10
06/17/92	06/17/02	06/17/92	06/17/02		733,872	11
08/19/93	08/19/03	08/19/93	08/19/03	1,500,000	93,600	12
08/18/93	08/18/03	08/18/93	08/18/03	5,000,000	315,500	13
08/25/93	08/25/03	08/25/93	08/25/03	1,500,000	93,450	14
08/26/93	08/26/03	08/26/93	08/26/03	20,000,000	1,260,000	15
09/30/93	01/15/04	09/30/93	01/15/04	8,500,000	518,500	16
09/30/93	01/16/04	09/30/93	01/16/04	10,000,000	607,000	17
09/11/95	09/12/05	09/11/95	09/12/05	8,000,000	553,600	18
09/11/95	09/12/05	09/11/95	09/12/05	3,000,000	207,600	19
09/13/95	09/13/05	09/13/95	09/13/05	20,000,000	1,386,000	20
12/21/95	12/21/06	12/21/95	12/21/06	10,000,000	658,000	21
09/11/95	09/11/07	09/11/95	09/11/07	20,000,000	1,404,000	22
09/12/95	09/12/07	09/12/95	09/12/07	5,000,000	352,000	23
08/18/93	08/18/08	08/18/93	08/18/08	3,500,000	228,550	24
08/19/93	08/19/08	08/19/93	08/19/08	1,000,000	65,100	25
12/20/95	12/21/09	12/20/95	12/21/09	3,000,000	198,300	26
12/20/95	12/22/09	12/20/95	12/22/09	5,000,000	331,000	27
09/11/95	09/13/10	09/11/95	09/13/10	7,000,000	498,400	28
08/18/93	08/19/13	08/18/93	08/19/13	3,000,000	204,900	29
10/01/93	10/01/13	10/01/93	10/01/13	10,000,000	690,000	30
09/11/95	09/11/15	09/11/95	09/11/15	10,000,000	735,000	31
09/15/95	09/15/15	09/15/95	09/15/15	2,000,000	147,200	32
				2,093,860,000	182,204,172	33

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
01/12/92	01/12/22	01/12/92	01/12/22	3,000,000	252,000	1
01/13/92	01/13/22	01/13/92	01/13/22	7,000,000	587,300	2
08/14/92	08/14/22	08/14/92	08/14/22	25,000,000	2,062,500	3
08/18/93	08/18/23	08/18/93	18/18/23	3,000,000	215,700	4
12/20/95	12/19/25	12/20/95	12/22/25	15,000,000	1,072,500	5
12/22/95	12/22/25	12/22/95	12/22/25	2,000,000	144,000	6
						7
				237,000,000	18,026,897	8
						9
						10
						11
						12
						13
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						24
						25
						26
						27
						28
						29
						30
						31
						32
				2,093,860,000	182,204,172	33

Schedule Page: 256 Line No.: 11 Column: a

Medium Term Notes - 7.85% - Maturity Date 05/29/2002 - Debt expense was fully amortized.

Schedule Page: 256 Line No.: 13 Column: a

Medium Term Notes - 7.07% - Maturity Date 08/28/2002 - Debt expense was fully amortized.

Schedule Page: 256 Line No.: 14 Column: a

Medium Term Notes - 7.15% - Maturity Date 09/11/2002 - Debt expense was fully amortized.

Schedule Page: 256 Line No.: 15 Column: a

Medium Term Notes - 7.625% - Maturity Date 12/10/2002 - Debt expense was fully amortized.

Schedule Page: 256.1 Line No.: 2 Column: a

Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation. Outstanding balance of $100,000,000 is carried in account 205-therefore balance not included on this schedule.

Schedule Page: 256.1 Line No.: 2 Column: h

Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation. Outstanding balance of $100,000,000 is carried in account 205-therefore balance not included on this schedule.

Schedule Page: 256.1 Line No.: 3 Column: a

Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation. Outstanding balance of $200,000,000 is carried in account 205.

Schedule Page: 256.1 Line No.: 3 Column: h

Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation. Outstanding balance of $200,000,000 is carried in account 205.

Schedule Page: 256.1 Line No.: 10 Column: a

Medium Term Notes - 7.53% - Maturity Date 01/09/2002 - Debt expense was fully amortized.

Schedule Page: 256.1 Line No.: 11 Column: a

Medium Term Notes - 7.91% - Maturity Date 06/17/2002 - Debt expense was fully amortized.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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)	108,947,246
2		
3		
4	Taxable Income Not Reported on Books	
5	* See foot note page	-10,463,701
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Provision for tax expense	48,104,073
11	* See foot note page	3,968,255
12		
13		
14	Income Recorded on Books Not Included in Return	
15	* See foot note page	11,187,524
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	* See foot note page	117,127,833
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	22,240,516
28	Show Computation of Tax:	
29	Taxable Income	22,240,516
30	Income Tax Accrual	7,783,626
31	Less Credits	
32	Fuel Credit	
33	Adjustments:	
34	Prior Period Adjustments	-66,426,539
35	Tax Adjusting and Reclassification Entries	-31,916,145
36	Total Income Tax Accrual	-90,559,058
37		
38		
39	Operating income Taxes	-87,153,016
40	Non-Operating Income Taxes	-3,406,042
41	Net Income Taxes	-90,559,058
42		
43	The Company will join in filing a consolidated income tax return with	
44	its subsidiaries as listed on page 103.	

Schedule Page: 261 Line No.: 5 Column: b

(1) Taxable Income Not Reported on Books - CR (DR):

Contributions in Aid of Construction - Net	9,735,930
Tenaska AFUDC Net	(7,137,000)
Loss on ACRS/MACRS Property	(8,601,517)
Gain on Land Sale	(2,166,574)
Demand Charges - Net	22,492
Gain on Sale of Emission Allowances	(306,286)
Intercompany Interest Income	14,501
FAS 106 Net	1,948,914
Site Clean-up Costs/Recoveries - net	(3,974,161)
Total Line 5	(10,463,701)

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

(2) Deductions Recorded on Books Not Deducted in Return - DR (CR):

Amort. Of Expns Related to Bond Redemptions	871,562
Unallowable Civic and Political Expenses	1,419,927
Capitalized Interest	3,245,555
Colstrip Reclamation	1,362,338
Property Taxes Capitalized	289,558
Storm Damage Amortization	4,750,002
Deferred Compensation Accruals, Net of Pymnts	2,655,455
Energy Conservation Costs, Amortization	27,743,050
Adjustment to Travel & Entertainment Exp.	384,240
Officers Life Insurance	(1,042,830)
Amortization of Capitalized Colstrip Costs	706,981
Excess Book Amortization of WNP#3	3,526,620
Executive Incentive Program	590,136
Pension Expense	(19,535,895)
FAS 133 Book Loss	(11,611,501)
Electric Plant Acquisition Adjustment	37,000
Rate Case Expenses (Net of Amortization)	(2,358,429)
Vacation Pay	(552,045)
Inventory Adjustments	500,000
Officer SERPS	(2,476,884)
DSM Amortization net of cost	277,293
Amortization - Customer connect fees	14,964
Miscellaneous	(6,828,842)
Total Line 11	3,968,255

Schedule Page: 261 Line No.: 15 Column: b

(3) Income Recorded on Books Not Included in Return - CR (DR):

Allowance for Funds Used During Construction	4,548,335
Amortization of Reacquired Debt	2,448
Subsidiary Income Booked	4,903,035

Tax Exempt Interest	167,600
Deferred Revenue - Connext	1,749,996
AFUCE	(183,890)
Total Line 15	11,187,524

Schedule Page: 261 Line No.: 20 Column: b

(4) Deductions on Return Not Charged Against Book Income - DR (CR):

ADR Dismantling	987,576
Indirect Cost Adjustment - Current Year Adjustment	19,893,294
Payroll Taxes Charged to Retirements	230,056
State and Local Tax Adjustments	1,240,039
Tenaska Amortization	6,451,333
Costs Deductible for Bonds Redeemed in 2001	0
Bad Debt Adjustment	1,896,060
2002 Conservation Expenditures	9,861,202
Injuries & Damages	50,000
Deferred Stock Options - WECO	(2,374)
Virtual Right of Way	3,085,698
Depreciation Adjustment	72,362,184
Cabot Gas Contract Purchase	1,072,765
Total Line 20	117,127,833

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL					
2	Income	-2,647,808		-90,918,497	-94,943,086	-4,504,000
3	Unemployment	13,910		1,202,043	1,191,179	
4	FICA	-13,948		11,330,744	11,163,549	
5	Other Federal Taxes	-572	15,767	22,392	7,444	
6	SUBTOTAL	-2,648,418	15,767	-78,363,318	-82,580,914	-4,504,000
7						
8	STATE OF WASHINGTON					
9	Property	35,346,495		33,322,650	32,891,873	10,836
10	State Excise	9,542,020		77,527,298	79,398,739	
11	Municipal Excise	9,195,944		67,770,110	67,231,585	
12	Other State Taxes	883,451		2,761,036	3,178,724	-50
13	SUBTOTAL	54,967,910		181,381,094	182,700,921	10,786
14						
15	TAXES-STATES OTHER					
16	Property	4,119,435		15,085,387	9,040,397	
17	Corporate License	1,301,916		-547,866	350,000	
18	Other Taxes	440,121		1,630,000	1,646,551	
19	SUBTOTAL	5,861,472		16,167,521	11,036,948	
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	58,180,964	15,767	119,185,297	111,156,955	-4,493,214

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-3,127,219		-43,578,530			-47,339,967	2
24,774		564,099			637,944	3
153,247		5,317,327			6,013,417	4
240	1,631				22,392	5
-2,948,958	1,631	-37,697,104			-40,666,214	6
						7
						8
35,788,108		22,048,218			11,274,432	9
7,670,579		50,095,584			27,431,714	10
9,734,469		38,868,432			28,901,678	11
465,713					2,761,036	12
53,658,869		111,012,234			70,368,860	13
						14
						15
10,164,425		15,085,387				16
404,050		-547,866				17
423,570		1,630,000				18
10,992,045		16,167,521				19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
61,701,956	1,631	89,482,651			29,702,646	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7							
8	TOTAL						
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12	4%	5,135			411.4	1,601	
13	7%	16,216			411.4	109	
14	10%	4,661,921			411.4	659,017	
15							
16	TOTAL	4,683,272				660,727	
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
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37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
3,534			12
16,107			13
4,002,904			14
			15
4,022,545			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			29
			30
			31
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			33
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			43
			44
			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	DEFERRED COMP-SALARY	21,120,021	232	9,358,698	12,014,153	23,775,476
2	FAS 87 PENSION	23,136,891	211, 186	539	-5,335,352	17,801,000
3	SPEC EMP RETIREMNT BENEFIT	5,745,509	232	6,051,354	2,056,256	1,750,411
4	SFAS 106 UNFUNDED LIABILITY	8,463,621	131	2,232,384	3,959,297	10,190,534
5	EXECUTIVE INCENTIVE PLANS	6,129,666	232, 417	5,187,386	5,655,003	6,597,283
6	DEFERRD INTERCHNG POWER	257,018	555	8,597,313	8,368,177	27,882
7	MISC. ITEMS	120,428	Various	102,630	101,333	119,131
8	DEFERRED STOCK OPTIONS	50,975	232, 417	13,999	16,373	53,349
9	PSE Non-qual retiremnt plan liab	21,942,148	232	16,637,205	11,147,199	16,452,142
10	COLSTRIP 3&4 FINAL	1,037,374	232		1,362,337	2,399,711
11	UNCLAIMED PROPERTY		131	188,004	205,252	17,248
12	UNEARNED REVENUE	461,597	Various	1,687,162	2,117,181	891,616
13	OTHER DFRD CREDIT- ADS	16,869,625	Various	1,749,996		15,119,629
14	DEFERRED CREDIT UTILICORP		Various		21,425,000	21,425,000
15	RESIDNT EXCHNG-DFRD CRDT	6,071,851	555	277,955,056	299,156,546	27,273,341
16	FAS 133 UNREALIZED LOSS	31,827,597	Various	47,079,189	15,251,592	
17	UNAPPL CONS & RECEIV DISC	765,000	232		3,067,500	3,832,500
18	UNEARND REV-POLE CONTACT	1,109,193	454	3,437,952	3,574,384	1,245,625
19	ENVIRONMENTAL REMEDIATION	8,617,573	232	8,617,573		
20	UNALLOC LAWSUIT INSURANCE		Various		375,000	375,000
21	Centralia fuel refund recl. tax		419, 421	840,085	840,085	
22	INTERIM RELIEF UE-011411		456		643,539	643,539
23	LOW INCOME PROGRAM		908	1,952,075	5,713,648	3,761,573
24	CONTRA LOW INCOME PROGRAM		Various	362,420		-362,420
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
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41						
42						
43						
44						
45						
46						
47	TOTAL	153,726,087		392,051,020	391,714,503	153,389,570

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

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

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

NOTES

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

3. Use footnotes as required.

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

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	316,999,284	11,891,171	257,000
3	Gas	98,438,895	34,015,780	19,171,000
4				
5	TOTAL (Enter Total of lines 2 thru 4)	415,438,179	45,906,951	19,428,000
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	415,438,179	45,906,951	19,428,000
10	Classification of TOTAL			
11	Federal Income Tax			
12	State Income Tax			
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
				190	88,000	328,721,455	2
						113,283,675	3
							4
					88,000	442,005,130	5
							6
							7
							8
					88,000	442,005,130	9
							10
							11
							12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 2 Column: k

	Beginning Balance	Debits to Acct 410.1	Credits to Acct 411.1	Adjustments Account Debited	Adjustments Amount	Ending Balance
Major Projects - Property Taxes	3,938,000		251,000			3,687,000
Pre 1981 Additions	4,013,597	(2,460,854)				1,552,743
Post 1980 Additions	308,064,813	14,352,025		190	88,000	322,504,838
Colstrip 3 & 4	950,000		6,000			944,000
Other	32,874					32,874
Total	316,999,284	11,891,171	257,000		88,000	328,721,455

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	SFAS 109	182,854,689		
4	WNP #3	17,456,392		1,126,218
5	Storm Damage	8,364,000		1,662,000
6	Tenaska	11,232,000	3,062,000	565,000
7	VROW Program	8,992,000	1,080,000	
8	Other	9,113,776	73,675,946	2,647,890
9	TOTAL Electric (Total of lines 3 thru 8)	238,012,857	77,817,946	6,001,108
10	Gas			
11	Deferred Gas Accounts	52,723,458	40,942,890	419,000
12	Thermal Group	-887,118		
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	51,836,340	40,942,890	419,000
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	289,849,197	118,760,836	6,420,108
20	Classification of TOTAL			
21	Federal Income Tax			
22	State Income Tax			
23	Local Income Tax			

NOTES

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

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

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

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		182	25,958,000			156,896,689	3
						16,330,174	4
						6,702,000	5
						13,729,000	6
						10,072,000	7
	5,076			190	7,785,000	87,921,756	8
	5,076		25,958,000		7,785,000	291,651,619	9
							10
594,000						93,841,348	11
						-887,118	12
							13
							14
							15
							16
594,000						92,954,230	17
							18
594,000	5,076		25,958,000		7,785,000	384,605,849	19
							20
							21
							22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 8 Column: k

	Beginning Balance	Debits to Acct 410.1	Credits to Acct 411.1	Debits to Acct 411.2	Adjustments Account Debited	Adjustments Amount	Ending Balance
Duvall Sub Land Exchange	3,665						3,665
SAP Amortization		1,776,280	932,000		190	6,035,000	6,879,280
1/16/00 Wind Storm Damage	947,000						947,000
Bond Redemptions	2,649,000		344,000				2,305,000
Conservation AFUCE	356,290		183,890				172,400
Interest Income-HEDC	(11,180)			5,076			(16,256)
Superfund Site Cleanup	692,000		615,000				77,000
Cabot Gas Contract Purchase	4,477,000	253,000.00	573,000				4,157,000
Deferred FAS 133		36,183					36,183
Repair Allowance - Electric		(1,207,500)			190	1,750,000	542,500
IRS Carryover Adjustments		22,985,330					22,985,330
Indirect Cost Adjustments		49,832,653					49,832,653
Total	9,113,776	73,675,946	2,647,890	5,076		7,785,000	87,921,756

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

OTHER REGULATORY LIABILITIES (Account 254)

1. Reporting below the particulars (Details) called for concerning other regulatory liabilities which are created through the rate-making actions of regulatory agencies (and not includable in other amounts)
2. For regulatory Liabilities being amortized show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $50,000, whichever is Less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	DEBITS Account Credited (b)	DEBITS Amount (c)	Credits (d)	Balance at End of Year (e)
1	Rock Island Power Costs - 34 Years	555	263,586		1,728,381
2					
3	Whitehorn 2&3 Lease -21.5 Years	550	54,492		86,279
4					
5	Unamort Gain from Disposition of Allowances	411.8	407,901	89,173	3,111,985
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
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26					
27					
28					
29					
30					
31					
32					
33					
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36					
37					
38					
39					
40					
41	TOTAL		725,979	89,173	4,926,645

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. 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.
3. If increases or decreases from previous year (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	618,969,525	569,467,960
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	537,817,586	494,529,550
5	Large (or Ind.) (See Instr. 4)	91,399,202	270,298,986
6	(444) Public Street and Highway Lighting	12,290,311	11,310,639
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,260,476,624	1,345,607,135
11	(447) Sales for Resale	88,682,767	554,618,364
12	TOTAL Sales of Electricity	1,349,159,391	1,900,225,499
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	1,349,159,391	1,900,225,499
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,871,172	3,142,270
17	(451) Miscellaneous Service Revenues	9,282,540	7,910,151
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	10,350,173	6,928,301
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-21,681,125	-55,861,919
22	(456) Other Electric Transportation Revenues	2,306,617	2,537,315
23	(442) Commercial and Industrial Transportation	13,244,447	
24			
25			
26	TOTAL Other Operating Revenues	16,373,824	-35,343,882
27	TOTAL Electric Operating Revenues	1,365,533,215	1,864,881,617

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

ELECTRIC OPERATING REVENUES (Account 400)

4. 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.)
5. See pages 108-109, Important Changes During Year, for important new territory added and important rate increase or decreases.
6. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
				1
9,801,319	9,435,556	839,878	826,187	2
				3
7,974,498	7,850,160	104,274	100,016	4
1,395,544	2,485,043	3,968	4,016	5
82,463	77,550	1,923	1,749	6
				7
				8
				9
19,253,824	19,848,309	950,043	931,968	10
3,474,948	5,059,541	9	9	11
22,728,772	24,907,850	950,052	931,977	12
				13
22,728,772	24,907,850	950,052	931,977	14

Line 12, column (b) includes $ -7,118,117 of unbilled revenues.

Line 12, column (d) includes -102,811 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 11 Column: b

Includes optimization transactions reported net in the income statement as required by EITF 02-03, effective after June 30, 2002. Pior periods have been reclassified to conform with the current presentation.

Schedule Page: 300 Line No.: 11 Column: c

Includes optimization transactions reported net in the income statement as required by EITF 02-03, effective after June 30, 2002. Pior periods have been reclassified to conform with the current presentation.

Schedule Page: 300 Line No.: 11 Column: d

Includes optimization transactions reported net in the income statement as required by EITF 02-03, effective after June 30, 2002. Pior periods have been reclassified to conform with the current presentation.

Schedule Page: 300 Line No.: 11 Column: e

Includes optimization transactions reported net in the income statement as required by EITF 02-03, effective after June 30, 2002. Pior periods have been reclassified to conform with the current presentation.

Schedule Page: 300 Line No.: 14 Column: d

Total does not include 2,307,081 MWH of transportation.

Schedule Page: 300 Line No.: 14 Column: e

Total does not include 363,826 MWH of transportation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 RESIDENTIAL SALES					
2	07 Residential Services	1,887,505	119,580,880	170,136	11,094	0.0634
3	17 Res. Svc. Heating	5,765,628	364,434,051	424,352	13,587	0.0632
4	27 Optional Svc. Htg.	2,155,872	136,134,621	241,467	8,928	0.0631
5	37 Residential Svc. Htg.	34,463	2,212,551	3,640	9,468	0.0642
6	47 Off Peak Wtr. Htg.	2,059	137,262	283	7,276	0.0667
7	TOTAL	9,845,527	622,499,365	839,878	11,723	0.0632
8						
9	442-01 COMMERCIAL SALES					
10	00 Special Contract	46,616	4,721,820	2	23,308,000	0.1013
11	08 Res/Farm Gen. Svc.	270,932	16,537,557	25,995	10,422	0.0610
12	10 Res/Farm Pri. Gen. Svc.	28,483	1,180,173	13	2,191,000	0.0414
13	11 Res/Farm Sm Dmd Svc.	161,550	8,865,517	317	509,621	0.0549
14	12 Res/Farm Lg Dmd Svc.	16,167	829,910	10	1,616,700	0.0513
15	24 General Service	1,988,991	139,355,768	68,084	29,214	0.0701
16	25 Sm Dmd Gen. Svc.	2,439,007	181,400,632	5,680	429,403	0.0744
17	26 Lg Dmd Gen. Svc.	1,505,012	99,818,164	533	2,823,662	0.0663
18	29 Seas. Irrig. Drain Pump.	14,694	690,563	584	25,161	0.0470
19	31 Primary Gen. Svc.	1,047,695	60,657,446	336	3,118,140	0.0579
20	35 Seas. Irrig. Drain Pump.	5,183	129,684	1	5,183,000	0.0250
21	43 Opt. Pri. Tot. Elec. Svc.	181,812	11,610,038	171	1,063,228	0.0639
22	49 Hi Voltage Gen. Svc.	300,208	13,946,375	10	30,020,800	0.0465
23	55 Area Lighting	2,052	405,696	930	2,206	0.1977
24	56 Res/Farm Area Lighting	2,185	450,660	1,420	1,539	0.2063
25	58 Sv. Flood Lighting	1,883	272,122	176	10,699	0.1445
26	59 R/F Sv. Flood Lighting	69	12,510	11	6,273	0.1813
27	TOTAL	8,012,539	540,884,635	104,273	76,842	0.0675
28						
29						
30	442-03 INDUSTRIAL SALES					
31	00 Special Contract	-1,037	-3,881			0.0037
32	24 General Service	106,662	7,994,345	3,107	34,330	0.0750
33	25 Sm Dmd Gen. Svc.	243,894	19,067,094	604	403,798	0.0782
34	26 Lg Dmd Gen. Svc.	320,068	22,379,739	109	2,936,404	0.0699
35	31 Primary General Svc.	548,880	32,527,071	123	4,462,439	0.0593
36	46 Hi Voltage Interrupt. Svc.	29,496	1,307,020	2	14,748,000	0.0443
37	49 Hi Voltage Interrupt. Svc.	168,143	8,649,042	8	21,017,875	0.0514
38	TOTAL	1,416,106	91,920,430	3,953	358,236	0.0649
39						
40						
41	TOTAL Billed	21,672,093	1,283,540,383	950,052	22,811	0.0592
42	Total Unbilled Rev.(See Instr. 6)	-102,811	-7,118,117	0	0	0.0692
43	TOTAL	21,569,282	1,276,422,266	950,052	22,703	0.0592

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	444 PUBLIC ST & HWY LGHTNG					
2	03 Special Contract	7	436	1	7,000	0.0623
3	24 General Service	6,126	448,911	338	18,124	0.0733
4	25 Sm Dmd Gen. Svc.	994	75,652	6	165,667	0.0761
5	50 Street Lighting-Incand.	546	43,122	10	54,600	0.0790
6	52 Cust. Owned - Merc Vp	2,708	442,302	308	8,792	0.1633
7	53 Street Lighting - Sod. Vap.	46,641	9,336,789	1,095	42,595	0.2002
8	54 Cust. Owned - Sod. Vap.	14,741	1,129,215	45	327,578	0.0766
9	57 Cont. Lighting Service	10,700	813,884	120	89,167	0.0761
10	TOTAL	82,463	12,290,311	1,923	42,882	0.1490
11						
12	442 TRANSPORTATION					
13	449 Hi Voltage - Commercial	58,392	674,802	1	58,392,000	0.0116
14	449 Hi Voltage - Industrial	1,732,371	10,941,847	11	157,488,273	0.0063
15	459 Special Contract - Industrial	516,318	3,934,415	4	129,079,500	0.0076
16	TOTAL	2,307,081	15,551,064	16	144,192,563	0.0067
17						
18						
19	447-01 Sales for Resale	8,377	394,578	9	930,778	0.0471
20	TOTAL	8,377	394,578	9	930,778	0.0471
21						
22						
23	Unbilled Revenue					
24	Residential	-52,517	-3,529,840			0.0672
25	Commercial	-42,740	-3,067,049			0.0718
26	Industrial	-7,554	-521,228			0.0690
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	21,672,093	1,283,540,383	950,052	22,811	0.0592
42	Total Unbilled Rev.(See Instr. 6)	-102,811	-7,118,117	0	0	0.0692
43	TOTAL	21,569,282	1,276,422,266	950,052	22,703	0.0592

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	SALES FOR RESALE - (A/C 447-01)					
2	Municipalities:					
3	Port of Seattle	RQ	Sch. 005			
4	Port of Bremerton	RQ	Sch. 005	.131	.131	.131
5	Poulsbo Port District	RQ	Sch. 005	.097	.097	.097
6	Port of Kingston	RQ	Sch. 005	.152	.152	.152
7	Kittitas P.U.D.	RQ	Sch. 005	.045	.045	.045
8	Port of Skagit Co. - Laconner	RQ	Sch. 005	.182	.182	.182
9	Port of Skagit Co.	RQ	Sch. 005	.107	.107	.107
10	Port of Brownsville	RQ	Sch. 005	.207	.207	.207
11	City of Des Moines	RQ	Sch. 005	.316	.316	.316
12	City of Oak Harbor	RQ	Sch. 005	.139	.139	.139
13	Misc. Adjustment	RQ	Sch. 005			
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SALES FOR RESALE (Account 447)

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1	SALES FOR RESALE (A/C 447-03)					
2	Other Utilites:					
3	Allegheny Energy Supply	OS	WSPP			
4	American Electric Power	OS	WSPP			
5	Amoco Energy	OS	WSPP			
6	Aquila Power Company	OS	WSPP			
7	Arizona Public Service	OS	WSPP			
8	Avista Energy	OS	WSPP			
9	Benton County PUD	OS	WSPP			
10	Black Hills Power	OS	WSPP			
11	Bonneville Power Admin.	OS	WSPP			
12	Burbank, City of	OS	WSPP			
13	California Dept. of Water Res.	OS	WSPP			
14	California ISO	OS	WSPP			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SALES FOR RESALE (Account 447)

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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)	Average Monthly CP Demand (f)
1	Calpine Corporation	OS	WSPP			
2	Cargill - Alliant	OS	WSPP			
3	Clastskanie PUD	OS	WSPP			
4	Conoco, Inc.	OS	WSPP			
5	Constellation Power	OS	WSPP			
6	Coral Power	OS	WSPP			
7	Douglas County PUD #1	OS	WSPP			
8	Duke Energy - DETM	OS	WSPP			
9	Dyenegy Marketing & Trade	OS	WSPP			
10	El Paso Energy Marketing	OS	WSPP			
11	Enmax	OS	WSPP			
12	Enron Power Marketing	OS	WSPP			
13	Epcor Merchant & Capital	OS	WSPP			
14	Eugene Water & Electric	OS	WSPP			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

SALES FOR RESALE (Account 447)

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1	Franklin County PUD	OS	WSPP			
2	Grant County PUD #2	OS	WSPP			
3	Grays Harbor PUD #1	OS	WSPP			
4	Hinson Power Company	OS	WSPP			
5	Idacorp	OS	WSPP			
6	Idaho Power Company	OS	WSPP			
7	Ilinova Power Marketing	OS	WSPP			
8	Klamath Falls	OS	WSPP			
9	Koch Power Supply Inc.	OS	WSPP			
10	Los Angeles, City of	OS	WSPP			
11	McMinnville Water & Light	OS	WSPP			
12	Mieco	OS	WSPP			
13	Modesto Irrigation District	OS	WSPP			
14	Montana Power Company	OS	WSPP			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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SALES FOR RESALE (Account 447)

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	(a)	(b)	(c)	(d)	(e)	(f)
1	Morgan Stanley Capital	OS	WSPP			
2	N. Calif. Power Agency	OS	WSPP			
3	NorAm Energy Services	OS	WSPP			
4	Northwestern Energy	OS	WSPP			
5	NP Energy	OS	WSPP			
6	Optimization Transactions	OS	WSPP			
7	Pacific NW Generating Corp	OS	WSPP			
8	Pacific Power & Light	OS	WSPP			
9	Pacificorp Power Marketing	OS	WSPP			
10	PG&E Energy Trading	OS	WSPP			
11	Portland General Electric	OS	WSPP			
12	Powerex	OS	WSPP			
13	PP&L Montana	OS	WSPP			
14	Public Service of Colorado	OS	WSPP			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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SALES FOR RESALE (Account 447)

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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Public Service Co of New Mexico	OS	WSPP			
2	Redding, City of	OS	WSPP			
3	Sacramento Municipal Dist.	OS	WSPP			
4	Salt River Project	OS	WSPP			
5	San Diego Gas & Electric	OS	WSPP			
6	Santa Clara, City of	OS	WSPP			
7	Seattle City Light	OS	WSPP			
8	Sempra Energy Trading	OS	WSPP			
9	Sierra Pacific Power	OS	WSPP			
10	Snohomish County PUD #1	OS	WSPP			
11	Southern Energy Marketing	OS	WSPP			
12	Tacoma, City of	OS	WSPP			
13	TransAlta Energy Marketing	OS	WSPP			
14	TransCanada Power Corp	OS	WSPP			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Turlock Irrigation District	OS	WSPP			
2	Utilicorps Network Canada	OS	WSPP			
3	Washington Water Power	OS	WSPP			
4	Western Area Power Assn	OS	WSPP			
5	Williams Energy Services	OS	WSPP			
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

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

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
					2
		-5,813	424	-5,389	3
776	8,272	27,272	2,729	38,273	4
611	6,076	21,464	2,907	30,447	5
813	9,570	28,584	1,553	39,707	6
171	2,837	5,992		8,829	7
1,171	11,469	41,156	2,230	54,855	8
629	6,744	22,096	1,196	30,036	9
1,379	13,013	48,451	2,604	64,068	10
1,986	19,924	69,809	3,717	93,450	11
841	8,764	29,536	904	39,204	12
			1,098	1,098	13
					14
8,377	86,669	288,547	19,362	394,578	
3,466,571	0	88,288,189	0	88,288,189	
3,474,948	**86,669**	**88,576,736**	**19,362**	**88,682,767**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
					2
112,800		2,505,900		2,505,900	3
323,325		8,694,513		8,694,513	4
135,040		3,554,821		3,554,821	5
165,401		4,293,651		4,293,651	6
26,600		933,030		933,030	7
426,966		11,363,592		11,363,592	8
1,687		40,636		40,636	9
1,025		18,450		18,450	10
22,472		656,440		656,440	11
1,993		45,049		45,049	12
					13
					14
8,377	86,669	288,547	19,362	394,578	
3,466,571	0	88,288,189	0	88,288,189	
3,474,948	**86,669**	**88,576,736**	**19,362**	**88,682,767**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
44,718		1,037,295		1,037,295	2
1,025		28,380		28,380	3
21,672		531,198		531,198	4
161,926		5,537,539		5,537,539	5
57,947		1,618,178		1,618,178	6
38					7
146,025		4,440,809		4,440,809	8
49,400		1,209,700		1,209,700	9
88,520		2,260,843		2,260,843	10
23,710		555,297		555,297	11
-1		-1		-1	12
15,324		487,779		487,779	13
33,080		758,205		758,205	14
8,377	86,669	288,547	19,362	394,578	
3,466,571	0	88,288,189	0	88,288,189	
3,474,948	**86,669**	**88,576,736**	**19,362**	**88,682,767**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
713		16,674		16,674	1
51,605		948,599		948,599	2
460		11,495		11,495	3
21,400		743,120		743,120	4
17,840		608,400		608,400	5
182,803		4,051,616		4,051,616	6
					7
29,986		954,834		954,834	8
61,400		1,689,201		1,689,201	9
114,973		2,599,662		2,599,662	10
					11
141,657		3,738,110		3,738,110	12
25,937		574,319		574,319	13
					14
8,377	86,669	288,547	19,362	394,578	
3,466,571	0	88,288,189	0	88,288,189	
3,474,948	**86,669**	**88,576,736**	**19,362**	**88,682,767**	

SALES FOR RESALE (Account 447) (Continued)

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

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

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
610,904		18,380,755		18,380,755	1
39,883		727,884		727,884	2
35,350		987,724		987,724	3
29,283		477,178		477,178	4
8,028		171,858		171,858	5
-2,417,704		-61,126,588		-61,126,588	6
4,787		85,272		85,272	7
514,962		11,534,654		11,534,654	8
75,360		2,478,544		2,478,544	9
34,200		693,650		693,650	10
213,519		4,737,770		4,737,770	11
217,388		5,671,739		5,671,739	12
70,538		1,720,387		1,720,387	13
134,395		3,004,244		3,004,244	14
8,377	86,669	288,547	19,362	394,578	
3,466,571	0	88,288,189	0	88,288,189	
3,474,948	**86,669**	**88,576,736**	**19,362**	**88,682,767**	

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
3,600		83,400		83,400	1
15,350		238,206		238,206	2
159,449		3,723,310		3,723,310	3
					4
15,200		344,677		344,677	5
274,376		6,100,822		6,100,822	6
27,729		638,635		638,635	7
208,697		5,596,871		5,596,871	8
27,850		174,224		174,224	9
8,830		176,855		176,855	10
400		9,743		9,743	11
3,003		80,922		80,922	12
355,882		8,023,043		8,023,043	13
17,095		538,486		538,486	14
8,377	86,669	288,547	19,362	394,578	
3,466,571	0	88,288,189	0	88,288,189	
3,474,948	**86,669**	**88,576,736**	**19,362**	**88,682,767**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
40,751		804,671		804,671	1
345		7,710		7,710	2
47,341		1,339,143		1,339,143	3
26,832		265,512		265,512	4
153,481		4,089,554		4,089,554	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
8,377	86,669	288,547	19,362	394,578	
3,466,571	0	88,288,189	0	88,288,189	
3,474,948	**86,669**	**88,576,736**	**19,362**	**88,682,767**	

Name of Respondent	This Report is:	Date of Report	Year of Report
Puget Sound Energy, Inc.	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/30/2003	Dec 31, 2002

FOOTNOTE DATA

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

Puget Sound Energy has no ownership interests or affiliations with the following companies.

Schedule Page: 310 Line No.: 13 Column: k

Charge to FERC 447 was reversed in 2003.

Schedule Page: 310.1 Line No.: 2 Column: a

Puget Sound Energy has no ownership interests or affiliations with the following companies.

Schedule Page: 310.2 Line No.: 12 Column: g

Prior year adjustments

Schedule Page: 310.2 Line No.: 12 Column: i

Prior year adjustments

Schedule Page: 310.2 Line No.: 12 Column: k

Prior year adjustments.

Schedule Page: 310.4 Line No.: 6 Column: g

Optimization transactions reclassified as purchases. Sales for Resale - Other Utilities is reported net of optimizaton transactions per EITF 02-03 effective after June 30, 2002.

Schedule Page: 310.4 Line No.: 6 Column: i

Optimization transactions reclassified as purchases. Sales for Resale - Other Utilities is reported net of optimizaton transactions per EITF 02-03 effective after June 30, 2002.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	114,567	323,844
5	(501) Fuel	31,644,944	31,127,476
6	(502) Steam Expenses	2,381,414	892,658
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	178,502	-317,453
10	(506) Miscellaneous Steam Power Expenses	10,175,065	7,186,411
11	(507) Rents	94,596	292,394
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	44,589,088	39,505,330
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,003,749	1,399,983
16	(511) Maintenance of Structures	1,006,421	924,102
17	(512) Maintenance of Boiler Plant	8,725,398	9,670,757
18	(513) Maintenance of Electric Plant	2,822,385	-773,889
19	(514) Maintenance of Miscellaneous Steam Plant	1,294,006	2,786,156
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	14,851,959	14,007,109
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	59,441,047	53,512,439
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	599,799	599,460
45	(536) Water for Power		38
46	(537) Hydraulic Expenses	1,262,850	1,509,479
47	(538) Electric Expenses	1,068,197	1,044,619
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,061,019	1,194,188
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	3,991,865	4,347,784

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	167,517	131,552
54	(542) Maintenance of Structures	531,491	385,137
55	(543) Maintenance of Reservoirs, Dams, and Waterways	673,759	880,025
56	(544) Maintenance of Electric Plant	870,828	1,280,484
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,284,102	950,565
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	3,527,697	3,627,763
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	7,519,562	7,975,547
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,001,023	509,158
63	(547) Fuel	81,892,668	250,277,352
64	(548) Generation Expenses	749,515	1,495,260
65	(549) Miscellaneous Other Power Generation Expenses	452,669	421,565
66	(550) Rents	9,329,486	6,261,674
67	TOTAL Operation (Enter Total of lines 62 thru 66)	93,425,361	258,965,009
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	402,187	417,198
70	(552) Maintenance of Structures	181,827	267,756
71	(553) Maintenance of Generating and Electric Plant	2,754,464	8,358,086
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	38,417	47,497
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	3,376,895	9,090,537
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	96,802,256	268,055,546
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	445,861,523	795,569,367
77	(556) System Control and Load Dispatching	737,885	801,662
78	(557) Other Expenses	11,397,437	10,035,647
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	457,996,845	806,406,676
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	621,759,710	1,135,950,208
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	893,911	626,717
84	(561) Load Dispatching	228,108	345,564
85	(562) Station Expenses	166,713	140,901
86	(563) Overhead Lines Expenses	299,840	258,945
87	(564) Underground Lines Expenses		
88	(565) Transmission of Electricity by Others	37,882,582	36,967,379
89	(566) Miscellaneous Transmission Expenses	523,161	493,136
90	(567) Rents	148,334	157,403
91	TOTAL Operation (Enter Total of lines 83 thru 90)	40,142,649	38,990,045
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	15,057	29,552
94	(569) Maintenance of Structures	3,102	10,243
95	(570) Maintenance of Station Equipment	631,802	989,448
96	(571) Maintenance of Overhead Lines	744,761	960,150
97	(572) Maintenance of Underground Lines	7,811	3,752
98	(573) Maintenance of Miscellaneous Transmission Plant		
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	1,402,533	1,993,145
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	41,545,182	40,983,190
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	2,051,180	1,057,563

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Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching	3,045,540	2,858,595
106	(582) Station Expenses	1,304,550	1,350,199
107	(583) Overhead Line Expenses	3,000,439	3,139,117
108	(584) Underground Line Expenses	2,763,333	2,714,888
109	(585) Street Lighting and Signal System Expenses	1,092,459	854,553
110	(586) Meter Expenses	1,935,178	1,552,134
111	(587) Customer Installations Expenses	2,270,598	2,400,968
112	(588) Miscellaneous Expenses	8,010,268	2,591,262
113	(589) Rents	113,848	143,143
114	TOTAL Operation (Enter Total of lines 103 thru 113)	25,587,393	18,662,422
115	Maintenance		
116	(590) Maintenance Supervision and Engineering		1,409
117	(591) Maintenance of Structures	10,491	3,337
118	(592) Maintenance of Station Equipment	3,342,490	2,557,244
119	(593) Maintenance of Overhead Lines	19,721,319	21,300,385
120	(594) Maintenance of Underground Lines	8,997,812	9,329,615
121	(595) Maintenance of Line Transformers	524,867	547,290
122	(596) Maintenance of Street Lighting and Signal Systems	1,456,857	1,487,987
123	(597) Maintenance of Meters	248,792	330,629
124	(598) Maintenance of Miscellaneous Distribution Plant	78,009	78,659
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	34,380,637	35,636,555
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	59,968,030	54,298,977
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	534,577	347,204
130	(902) Meter Reading Expenses	12,727,369	10,265,725
131	(903) Customer Records and Collection Expenses	12,724,963	12,408,216
132	(904) Uncollectible Accounts	7,092,346	6,939,337
133	(905) Miscellaneous Customer Accounts Expenses	-33,020	-18,987
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	33,046,235	29,941,495
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision		
138	(908) Customer Assistance Expenses	25,453,809	18,407,804
139	(909) Informational and Instructional Expenses	422,952	225,545
140	(910) Miscellaneous Customer Service and Informational Expenses	59,982	44,212
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	25,936,743	18,677,561
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision	171,244	133,986
145	(912) Demonstrating and Selling Expenses	854,478	696,128
146	(913) Advertising Expenses		10,630
147	(916) Miscellaneous Sales Expenses	180	22,142
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	1,025,902	862,886
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	13,643,527	12,277,901
152	(921) Office Supplies and Expenses	12,373,710	10,710,469
153	(Less) (922) Administrative Expenses Transferred-Credit	146,689	190,782

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	5,791,181	5,810,622
156	(924) Property Insurance	2,216,182	1,456,417
157	(925) Injuries and Damages	3,555,416	2,632,252
158	(926) Employee Pensions and Benefits	5,200,700	3,913,210
159	(927) Franchise Requirements		
160	(928) Regulatory Commission Expenses	3,737,896	3,485,073
161	(929) (Less) Duplicate Charges-Cr.		
162	(930.1) General Advertising Expenses		638
163	(930.2) Miscellaneous General Expenses	2,722,054	2,631,565
164	(931) Rents	2,563,849	2,580,574
165	TOTAL Operation (Enter Total of lines 151 thru 164)	51,657,826	45,307,939
166	Maintenance		
167	(935) Maintenance of General Plant	2,999,952	2,803,766
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	54,657,778	48,111,705
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	837,939,580	1,328,826,022

Schedule Page: 320 Line No.: 76 Column: b

Includes optimization transactions reported net in the income statement as required by EITF 02-03, effective after June 30, 2002. Pior periods have been reclassified to conform with the current presentation.

Schedule Page: 320 Line No.: 76 Column: c

Includes optimization transactions reported net in the income statement as required by EITF 02-03, effective after June 30, 2002. Pior periods have been reclassified to conform with the current presentation.

Schedule Page: 320 Line No.: 138 Column: c

In calculating 2001 electric costs per customer, Puget Sound Energy excludes $11,493,740 million in Personal Energy Management costs. Puget Sound Energy began providing Personal Energy Management billing information to electric customers in December 2000. Personal Energy Management consumption information is available to all classes of customers. Customers are able to monitor their energy usage and shift usage to low-demand off-peak periods. This program benefits overall conservation efforts by reducing the demand for peak power generation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	BC Hydro & Power Auth.	LF				
2	Bonneville Power Admin	LF				
3	Bonneville Power Admin	LF				
4	Bonneville Power Admin	LF				
5	Chelan County PUD #1	LF				
6	Chelan County PUD #1	LF				
7	Chelan County PUD #1	LF				
8	Chelan County PUD #1	LF				
9	Chelan County PUD #1	LF				
10	Chelan County PUD #1	LF				
11	Chelan County PUD #1	LF				
12	Chelan County PUD #1	LF				
13	Douglas County PUD #1	LF				
14	Grant County PUD #2	LF				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Grant County PUD #2	LF				
2	Montana Power	LF				
3	Northern Wasco County PUD	LF				
4	Pacificorp	LF				
5	Snohomish County PUD #1	LF				
6	Washington Water Power	LF				
7	Washington Water Power	LF				
8	Pacific Power & Light	LU				
9	Kahn-PURPA	LU				
10	Kingdom Energy - PURPA	LU				
11	Koma Kulshan Assoc. - PURPA	LU				
12	March Point - PURPA	LU				
13	March Point - PURPA	LU				
14	Pt. Townsend - PURPA	LU				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Puyallup Energy Recovery	LU				
2	Puyallup Energy Recovery	LU				
3	Puyallup Energy Recovery	LU				
4	Puyallup Energy Recovery	LU				
5	South Fork Assoc - PURPA	LU				
6	Spokane - PURPA	LU				
7	STS Hydro - PURPA	LU				
8	Sumas - PURPA	LU				
9	Tenaska - PURPA	LU				
10	Tenaska - PURPA	LU				
11	Twin Falls Assoc. - PURPA	LU				
12	Bonneville Power Admin	EX	FPC#63			
13	Pacific Gas & Electric	EX	FPC#91			
14	Powerex - Exchange	EX	FPC#158			
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Seattle	EX	PNCA			
2	Seattle	EX	PNCA			
3	Tacoma	EX	PNCA			
4	Washington Water Power	EX	PNCA			
5	Deviations	EX				
6	Arizona Public Service	EX				
7	Avista Energy	EX				
8	TransAlta Energy Marketing	EX				
9	Bonneville Power Admin	EX				
10	Allegheny Energy Supply	OS				
11	American Electric Power Services	OS				
12	American Electric Power Services	OS				
13	Amoco Energy Trading	OS				
14	Aquila Power Company	OS				
	Total					

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Aquila Power Company	OS				
2	Arizona Public Service	OS				
3	Avista Energy	OS				
4	Benton County PUD	OS				
5	Black Hills Power	OS				
6	Bonneville Power Admin	OS				
7	Burbank, City of	OS				
8	California Dept. of Water Resources	OS				
9	California ISO	OS				
10	Calpine Corporation	OS				
11	Cargill - Alliant	OS				
12	Chelan County PUD #1	OS				
13	Clatskanie PUD	OS				
14	Constellation Power	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Coral Power	OS				
2	Douglas County PUD#1	OS				
3	Duke Energy - DETM	OS				
4	Dynegy Marketing & Trade	OS				
5	El Paso Energy Marketing	OS				
6	ENMAX Energy	OS				
7	Enron Power Marketing	OS				
8	Epcor Merchant & Capital	OS				
9	Eugene Water & Electric	OS				
10	Franklin County PUD	OS				
11	Grant County PUD #2	OS				
12	Grays Harbor PUD #1	OS				
13	Idacorp	OS				
14	Idaho Power Company	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Klamath Falls	OS				
2	Koch Power Supply	OS				
3	Los Angeles, City of	OS				
4	Maclaren Energy	OS				
5	March Point Cogen. - 1	OS				
6	March Point Cogen. - 2	OS				
7	McMinnville Water & Light	OS				
8	MEGA	OS				
9	MIECO, Inc.	OS				
10	Modesto Irrigation	OS				
11	Morgan Stanely	OS				
12	Morgan Stanley	OS				
13	Northern Calif. Power Agency	OS				
14	New Mexico Public Service	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NorAm Energy Services, Inc.	OS				
2	Northwestern Energy	OS				
3	NP Energy	OS				
4	Pacific Northwest Generation Grp.	OS				
5	Pacific Power & Light	OS				
6	Pacificorp Power Marketing	OS				
7	PG&E Energy Trading	OS				
8	Pierce Power	OS				
9	Portland General Electric	OS				
10	Powerex	OS				
11	PP&L Montana	OS				
12	Public Service of Colorado	OS				
13	Redding	OS				
14	Richland, City of	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sacramento Municipal District	OS				
2	Salt River Project	OS				
3	San Diego Gas & Electric	OS				
4	Santa Clara, City of	OS				
5	Seattle City Light	OS				
6	Sempra Energy Trading	OS				
7	Sierra Pacific Power	OS				
8	Snohomish County PUD #1	OS				
9	Tacoma, City of	OS				
10	Tenaska - Cogen Tolling	OS				
11	TransAlta Energy Marketing	OS				
12	TransAlta Energy Marketing	OS				
13	TrasnCanada Power	OS				
14	Turlock Irrigation District	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	TXU Energy Company	OS				
2	Utilicorps Network Canada	OS				
3	Washington Water Power	OS				
4	West Kootenay Power	OS				
5	Williams Energy Services	OS				
6	Deferred Energy - Black Creek	OS				
7	Bonneville Pwr Admin-Amort. of WNP#3	OS				
8	Residential Exchange-Refunding (Sch94)	OS				
9	Optimization Transacations	OS				
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
19,454				1,302,737		1,302,737	1
139,543							2
398,759				10,780,257		10,780,257	3
1,177			97,337			97,337	4
					36,458	36,458	5
					4,145,055	4,145,055	6
				8,087,271		8,087,271	7
					-263,586	-263,586	8
					21,359,644	21,359,644	9
1,869,464				9,400,104		9,400,104	10
2,200,460				10,340,804		10,340,804	11
					14,315,882	14,315,882	12
1,173,335				10,450,612	-690,362	9,760,250	13
355,543				2,462,946		2,462,946	14
19,621,559	2,597,393	2,548,825	64,416,017	499,735,130	-53,842,076	510,309,071	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
389,316				3,934,204		3,934,204	1
615,198			28,126,680	2,723,871	51,022	30,901,573	2
35,842				2,255,564		2,255,564	3
1,051,901			36,192,000	18,439,423		54,631,423	4
89,728				3,605,982		3,605,982	5
216,810				10,220,295		10,220,295	6
6,020				66,789		66,789	7
2,597				41,454		41,454	8
20				936		936	9
635				31,919		31,919	10
39,621				2,968,564		2,968,564	11
418,571				25,548,388	170,463	25,718,851	12
683,653				37,125,420	4,047,515	41,172,935	13
2,116				53,176		53,176	14
19,621,559	2,597,393	2,548,825	64,416,017	499,735,130	-53,842,076	510,309,071	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
13,558				299,080		299,080	1
					65,000	65,000	2
					195,000	195,000	3
					99,900	99,900	4
13,014				968,730		968,730	5
143,028				12,647,771		12,647,771	6
854				26,814		26,814	7
856,213				64,699,998	9,596,805	74,296,803	8
1,285,696				73,561,188	22,819,991	96,381,179	9
					9,492,000	9,492,000	10
56,603				4,244,550	189,933	4,434,483	11
	7,000						12
	412,996	412,996					13
	1,180,792	1,180,792			-4,596,136	-4,596,136	14
19,621,559	2,597,393	2,548,825	64,416,017	499,735,130	-53,842,076	510,309,071	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	155,000				149,710	149,710	1
		155,000					2
					41,255	41,255	3
							4
	42,972						5
	261,526	261,526					6
	448,856	448,856			-111,617	-111,617	7
	20,000	20,000			-13,000	-13,000	8
	60,000	60,000			90,000	90,000	9
166,058				4,025,200		4,025,200	10
67,919				1,343,938		1,343,938	11
238,962				6,431,567		6,431,567	12
192,298				5,196,582		5,196,582	13
					1,675,664	1,675,664	14
19,621,559	2,597,393	2,548,825	64,416,017	499,735,130	-53,842,076	510,309,071	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
249,919				5,523,941		5,523,941	1
34,196				747,269		747,269	2
546,828				14,514,379		14,514,379	3
7,218				159,369		159,369	4
30,319				924,399		924,399	5
497,180				10,272,373		10,272,373	6
40				520		520	7
13,957				315,765		315,765	8
				26,707		26,707	9
69,006				1,531,604		1,531,604	10
49,097				1,184,806		1,184,806	11
78,210				1,794,100		1,794,100	12
966				23,920		23,920	13
121,098				3,538,587		3,538,587	14
19,621,559	2,597,393	2,548,825	64,416,017	499,735,130	-53,842,076	510,309,071	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received	MegaWatt Hours Delivered	Demand Charges ($)	Energy Charges ($)	Other Charges ($)	Total (j+k+l) of Settlement ($)	
(g)	(h)	(i)	(j)	(k)	(l)	(m)	
54,332				1,184,208		1,184,208	1
333,899				5,261,427		5,261,427	2
210,260				3,717,876		3,717,876	3
111,600				2,432,100		2,432,100	4
78,150				2,144,991		2,144,991	5
16,320				359,796		359,796	6
				-585,125		-585,125	7
22,025				749,837		749,837	8
48,108				887,475		887,475	9
2,674				68,623		68,623	10
122,602				3,114,608		3,114,608	11
6,059				142,161		142,161	12
28,254				831,590		831,590	13
213,001				5,149,436		5,149,436	14
19,621,559	2,597,393	2,548,825	64,416,017	499,735,130	-53,842,076	510,309,071	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
19,715				397,816		397,816	1
52,425				1,600,113		1,600,113	2
6,518				187,759		187,759	3
							4
							5
				-31,866		-31,866	6
							7
							8
177,782				4,049,862		4,049,862	9
7,152				152,270		152,270	10
418,604				16,676,233		16,676,233	11
				322,200		322,200	12
9,528				295,515		295,515	13
4,000				75,200		75,200	14
19,621,559	2,597,393	2,548,825	64,416,017	499,735,130	-53,842,076	510,309,071	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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MegaWatt Hours Purchased	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received	MegaWatt Hours Delivered	Demand Charges ($)	Energy Charges ($)	Other Charges ($)	Total (j+k+l) of Settlement ($)	
(g)	(h)	(i)	(j)	(k)	(l)	(m)	
80,500				2,087,788		2,087,788	1
30,798				791,508		791,508	2
10,664				268,217		268,217	3
92,857				1,804,033		1,804,033	4
491,391				12,171,958		12,171,958	5
47,277				1,433,795		1,433,795	6
79,000				2,162,950		2,162,950	7
10,323				240,817	5,851,034	6,091,851	8
191,571				4,562,733		4,562,733	9
272,652				8,807,937		8,807,937	10
186,762				4,006,385		4,006,385	11
218,219				5,446,683		5,446,683	12
816				19,152		19,152	13
				-3		-3	14
19,621,559	2,597,393	2,548,825	64,416,017	499,735,130	-53,842,076	510,309,071	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
25,678				1,029,119		1,029,119	1
							2
4,000				102,200		102,200	3
90,215				2,096,590		2,096,590	4
118,110				2,317,163		2,317,163	5
241,763				6,858,967		6,858,967	6
4,750				134,925		134,925	7
36,185				620,859		620,859	8
102,408				1,836,584		1,836,584	9
10,543				340,511		340,511	10
399,295				10,778,465		10,778,465	11
				252,000		252,000	12
7,506				599,456		599,456	13
79,230				1,637,634		1,637,634	14
19,621,559	2,597,393	2,548,825	64,416,017	499,735,130	-53,842,076	510,309,071	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
400				10,500		10,500	1
25				450		450	2
90,358				1,273,506		1,273,506	3
				451		451	4
134,455				3,013,819		3,013,819	5
	8,251	9,655			-68,392	-68,392	6
					3,526,620	3,526,620	7
					-149,970,482	-149,970,482	8
178,800					3,952,548	3,952,548	9
							10
							11
							12
							13
							14
19,621,559	2,597,393	2,548,825	64,416,017	499,735,130	-53,842,076	510,309,071	

Schedule Page: 326 Line No.: 1 Column: b

Pt. Roberts contract expires with a six month notice.

Schedule Page: 326 Line No.: 2 Column: b

CSPE contract expires March 31, 2003.

Schedule Page: 326 Line No.: 3 Column: b

Bonneville Exchange Power contract expires June 30, 2019.

Schedule Page: 326 Line No.: 4 Column: b

Supplemental & Entitlement contract expires March 31, 2003.

Schedule Page: 326 Line No.: 5 Column: b

Rock Island contract expires June 7, 2012.

Schedule Page: 326 Line No.: 6 Column: b

Rock Island contract expires June 7, 2012.

Schedule Page: 326 Line No.: 7 Column: b

Rock Island contract expires June 7, 2012.

Schedule Page: 326 Line No.: 8 Column: b

Rock Island contract expires June 7, 2012.

Schedule Page: 326 Line No.: 9 Column: b

Rock Island contract expires June 7, 2012.

Schedule Page: 326 Line No.: 10 Column: b

Rock Island contract expires June 7, 2012.

Schedule Page: 326 Line No.: 11 Column: b

Rocky Reach contract expires November 1, 2011.

Schedule Page: 326 Line No.: 12 Column: b

Rocky Reach contract expires November 1, 2011.

Schedule Page: 326 Line No.: 13 Column: b

Wells Project contract expires August 31, 2018.

Schedule Page: 326 Line No.: 13 Column: l

Includes ($690,362) annual adjustment for the contract year 2001-2002

Schedule Page: 326 Line No.: 14 Column: b

Priest Rapids contract expires October 31, 2005.

Schedule Page: 326.1 Line No.: 1 Column: b

Wanapum contract expires October 31, 2009.

Schedule Page: 326.1 Line No.: 2 Column: b

Contract expires December 29, 2010.

Schedule Page: 326.1 Line No.: 3 Column: b

Dalles Dam Fishway contract expires December 31, 2012.

Schedule Page: 326.1 Line No.: 4 Column: b

Contract expires Octoebr 31, 2003.

Schedule Page: 326.1 Line No.: 5 Column: b

Conservation Power Sales Agreement expires February 28, 2010.

Schedule Page: 326.1 Line No.: 6 Column: b

Contract expires December 31, 2002.

Schedule Page: 326.1 Line No.: 7 Column: b

Contract expires December 31, 2002.

Schedule Page: 326.1 Line No.: 12 Column: l

Displaced power costs.

Schedule Page: 326.1 Line No.: 13 Column: l

Displaced power costs.

Schedule Page: 326.2 Line No.: 8 Column: l

Displaced power costs.

Schedule Page: 326.2 Line No.: 9 Column: l

Displaced power costs.

Schedule Page: 326.2 Line No.: 14 Column: l

Fee charged to Powerex when exchange power is delivered to them.

Schedule Page: 326.9 Line No.: 9 Column: a

The purchases on this page are reported gross. Purchases per the income statement are reported net of optimization transactions of $(64,447,545) as required by EITF 02-03 effective after June 30, 2002.

Schedule Page: 326.9 Line No.: 9 Column: g

Add back optimizations transactions amounts that were netted against individual counterparty purchase amounts in July 2002 only. Transactions on this page are reported gross.

Schedule Page: 326.9 Line No.: 9 Column: l

Add back optimizations transactions amounts that were netted against individual counterparty purchase amounts in July 2002 only. Transactions on this page are reported gross.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i. e., wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:
LF - for Long-term firm transmission service. "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 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.
SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Bonneville Power Admin	Bonneville Power Admin	City of Blaine	LF
2	Bonneville Power Admin	Bonneville Power Admin	Georgia Pacific	LF
3	Bonneville Power Admin	Bonneville Power Admin	Kittitas County	LF
4	Bonneville Power Admin	Bonneville Power Admin	Orcas Power & Light	LF
5	Bonneville Power Admin	Bonneville Power Admin	City of Sumas	LF
6	Bonneville Power Admin	Bonneville Power Admin	Tanner Electric Cooperative	LF
7	Bonneville Power Admin	Bonneville Power Admin	Tanner Electric Cooperative	LF
8	Bonneville Power Admin	Bonneville Power Admin	Tanner Electric Cooperative	LF
9	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	LF
10	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	LF
11	Whatcom County PUD	Whatcom County PUD	Whatcom County PUD	LF
12	Whatcom County PUD	Whatcom County PUD	Whatcom County PUD	LF
13	Whatcom County PUD	Whatcom County PUD	Whatcom County PUD	LF
14	Tacoma City Light	Tacoma City Light	Tacoma City Light	LF
15	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	LF
16	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	LF
17	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	LF
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i. e., wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:
LF - for Long-term firm transmission service. "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 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.
SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Bonneville Power Admin	Bonneville Power Admin	Port Townsend Paper Company	LF
2	Seattly City Light	Seattly City Light	Seattly City Light	LF
3	Seattly City Light	Seattly City Light	Seattly City Light	LF
4	Seattly City Light	Seattly City Light	Seattly City Light	LF
5	Washington Water Power	Black Creek Hydro, Inc.	Washingto Water Power	LF
6	Aquila Power Company	Various	Various	OS
7	Avista Energy	Various	Various	OS
8	Bonneville Power Admin	Various	Various	OS
9	Cargill -Alliant	Various	Various	OS
10	Eugene Water & Electric	Various	Various	OS
11	Idaho Power	Various	Various	OS
12	Montana Power	Various	Various	OS
13	Pacific NW Generation	Various	Various	OS
14	Pacificorp	Various	Various	OS
15	PG&E Energy Trading	Various	Various	OS
16	Powerex	Various	Various	OS
17	PPL Energy Plus	Various	Various	OS
	TOTAL			

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i. e., wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:
LF - for Long-term firm transmission service. "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 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.
SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Sempra Energy Trading	Various	Various	OS
2	Seattle City Light	Various	Various	OS
3	Snohomish County PUD	Various	Various	OS
4	Southern Energy	Various	Various	OS
5	TransAlta Energy	Various	Various	OS
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.

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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FPC#16	Custer Substation	Blaine Substation		64,649	64,649	1
FPC#16	Bellingham Sub	Chlorine Plant Sub				2
FPC#16	White River Sub	Teanaway Substation		14,660	14,660	3
FPC#16	Murray B'hm S Wo Tap	Fidalgo Substation		154,910	154,910	4
FPC#16	Bellingham Sub	Sumas Tap		20,881	20,881	5
FPC#16	Maple Valley Sub	Ames Lake Tap		19,612	19,612	6
FPC#16	Olympia Substation	Luhr Beach Tap		10,745	10,745	7
FPC#16	Maple Valley Sub	North Bend Sub		4,961	4,961	8
FPC#28	Beverly Park Sub	Beverly Park Sub		333,972	333,972	9
FPC #88	Beverly Park Sub	East Arlington Sub				10
FPC#32	Bellingham Sub	Enterprise Sub	1	3,204	3,204	11
FPC#18	Bellingham Sub	Ferndale Sub	1	9,379	9,379	12
FPC#79	Bellingham Sub	Olympic Tap-BP Ref.				13
FPC#62	Starwood Substation	Baldi Substation	2	2,783	2,783	14
FPC#60	Beverly Park Sub	Goldbar Sub				15
FPC#28	Beverly Park Sub	Hilton Lake Sub	19	68,405	68,405	16
FPC#28	Beverly Park Sub	Olympic Pipe Sub	1	13,670	13,670	17
			41	**4,564,763**	**4,564,763**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.

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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
FPC#95	Fairmount Substaion	Port Townsend Tap				1
FPC#78	Paul Sub at Centrala	Talbot Hill Sub				2
FPC#155	Stillwater Sub	Bothell Substaion	17			3
FPC#155	Stillwater Sub	NC Machinery Tap				4
FPC#55	Black Creek Hydro	Mid Columbia Projecs				5
FPC#1	Various	Various				6
FPC#1	Various	Various				7
FPC#1	Various	Various		876,960	876,960	8
FPC#1	Various	Various		8,400	8,400	9
FPC#1	Various	Various		120	120	10
FPC#1	Various	Various		2,033,360	2,033,360	11
FPC#1	Various	Various		59,264	59,264	12
FPC#1	Various	Various				13
FPC#1	Various	Various				14
FPC#1	Various	Various		175	175	15
FPC#1	Various	Various		560,990	560,990	16
FPC#1	Various	Various		150	150	17
			41	**4,564,763**	**4,564,763**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.
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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
FPC#1	Various	Various		462	462	1
FPC#1	Various	Various		10,034	10,034	2
FPC#1	Various	Various		19,440	19,440	3
FPC#1	Various	Various		42,452	42,452	4
FPC#1	Various	Various		231,125	231,125	5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
			41	**4,564,763**	**4,564,763**	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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 (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. Provide total amounts in column (i) through (n) as the last Line. Enter "TOTAL" in column (a) as the Last Line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
46,111			46,111	1
				2
79,424			79,424	3
23,130			23,130	4
82,950			82,950	5
18,256			18,256	6
229			229	7
58,844			58,844	8
				9
				10
1,012		27,000	28,012	11
1,922			1,922	12
				13
4,576			4,576	14
		707	707	15
8,460		600	9,060	16
1,450		600	2,050	17
658,667	**9,143,725**	**28,907**	**9,831,299**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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 (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. Provide total amounts in column (i) through (n) as the last Line. Enter "TOTAL" in column (a) as the Last Line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
				2
304,612			304,612	3
				4
27,691			27,691	5
				6
	13,101		13,101	7
	1,204,682		1,204,682	8
	12,369		12,369	9
	155		155	10
	6,186,321		6,186,321	11
	105,621		105,621	12
				13
				14
	226		226	15
	778,840		778,840	16
	306		306	17
658,667	**9,143,725**	**28,907**	**9,831,299**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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 (I), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. Provide total amounts in column (i) through (n) as the last Line. Enter "TOTAL" in column (a) as the Last Line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	349		349	1
	39,967		39,967	2
	6,940		6,940	3
	112,044		112,044	4
	682,804		682,804	5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
658,667	**9,143,725**	**28,907**	**9,831,299**	

Schedule Page: 328 Line No.: 1 Column: d

Contract expires with one year written notice.

Schedule Page: 328 Line No.: 1 Column: f

Facility not owned by Puget Sound Energy.

Schedule Page: 328 Line No.: 2 Column: d

Contract expires with one year written notice.

Schedule Page: 328 Line No.: 2 Column: f

Facility not owned by Puget Sound Energy.

Schedule Page: 328 Line No.: 3 Column: d

Contract expires with one year written notice.

Schedule Page: 328 Line No.: 3 Column: g

Facility not owned by Puget Sound Energy.

Schedule Page: 328 Line No.: 4 Column: d

Contract expires with one year written notice.

Schedule Page: 328 Line No.: 4 Column: g

Facility not owned by Puget Sound Energy.

Schedule Page: 328 Line No.: 5 Column: d

Contract expires with one year written notice.

Schedule Page: 328 Line No.: 5 Column: f

Facility not owned by Puget Sound Energy.

Schedule Page: 328 Line No.: 6 Column: d

Contract expires with one year written notice.

Schedule Page: 328 Line No.: 6 Column: f

Facility not owned by Puget Sound Energy.

Schedule Page: 328 Line No.: 7 Column: d

Contract expires with one year written notice.

Schedule Page: 328 Line No.: 7 Column: f

Facility not owned by Puget Sound Energy.

Schedule Page: 328 Line No.: 8 Column: d

Contract expires with one year written notice.

Schedule Page: 328 Line No.: 8 Column: f

Facility not owned by Puget Sound Energy.

Schedule Page: 328 Line No.: 9 Column: d

Contract expires with one year written notice.

Schedule Page: 328 Line No.: 10 Column: d

Contract expires with one year written notice.

Schedule Page: 328 Line No.: 10 Column: g

Facility not owned by Puget Sound Energy.

Schedule Page: 328 Line No.: 11 Column: d

Contract expires with one year written notice.

Schedule Page: 328 Line No.: 11 Column: f

Facility not owned by Puget Sound Energy.

Schedule Page: 328 Line No.: 11 Column: g

Facility not owned by Puget Sound Energy.

Schedule Page: 328 Line No.: 11 Column: m

Use of facilities charges.

Schedule Page: 328 Line No.: 12 Column: d

Contract expires with one year written notice.

FOOTNOTE DATA

Schedule Page: 328 Line No.: 12 Column: f
Facility not owned by Puget Sound Energy.
Schedule Page: 328 Line No.: 12 Column: g
Facility not owned by Puget Sound Energy.
Schedule Page: 328 Line No.: 13 Column: d
Contract expires with one year written notice.
Schedule Page: 328 Line No.: 13 Column: f
Facility not owned by Puget Sound Energy.
Schedule Page: 328 Line No.: 13 Column: g
Facility not owned by Puget Sound Energy.
Schedule Page: 328 Line No.: 14 Column: d
Contract expires with one year written notice.
Schedule Page: 328 Line No.: 14 Column: g
Facility not owned by Puget Sound Energy.
Schedule Page: 328 Line No.: 15 Column: d
Contract expires with two years written notice.
Schedule Page: 328 Line No.: 15 Column: g
Facility not owned by Puget Sound Energy.
Schedule Page: 328 Line No.: 15 Column: m
Use of facilities charges.
Schedule Page: 328 Line No.: 16 Column: d
Contract expires with two years written notice.
Schedule Page: 328 Line No.: 16 Column: g
Facility not owned by Puget Sound Energy.
Schedule Page: 328 Line No.: 16 Column: m
Use of facilities charges.
Schedule Page: 328 Line No.: 17 Column: d
Contract expires with two years written notice.
Schedule Page: 328 Line No.: 17 Column: g
Facility not owned by Puget Sound Energy.
Schedule Page: 328 Line No.: 17 Column: m
Use of facilities charges.
Schedule Page: 328.1 Line No.: 1 Column: d
Expires with verbal or written notice.
Schedule Page: 328.1 Line No.: 1 Column: f
Facility not owned by Puget Sound Energy.
Schedule Page: 328.1 Line No.: 2 Column: d
Contract expires September 2005.
Schedule Page: 328.1 Line No.: 2 Column: f
Facility not owned by Puget Sound Energy.
Schedule Page: 328.1 Line No.: 3 Column: d
Contract expires June 2020.
Schedule Page: 328.1 Line No.: 3 Column: g
Facility not owned by Puget Sound Energy.
Schedule Page: 328.1 Line No.: 4 Column: d
Contract expires December 2002.
Schedule Page: 328.1 Line No.: 5 Column: d
Contract expires with 120 days written notice.
Schedule Page: 328.1 Line No.: 5 Column: g

Facility not owned by Puget Sound Energy.

Schedule Page: 328.1 Line No.: 6 Column: d

Non-firm transmission service.

Schedule Page: 328.1 Line No.: 7 Column: d

Non-firm transmission service.

Schedule Page: 328.1 Line No.: 8 Column: d

Non-firm transmission service.

Schedule Page: 328.1 Line No.: 9 Column: d

Non-firm transmission service.

Schedule Page: 328.1 Line No.: 10 Column: d

Non-firm transmission service.

Schedule Page: 328.1 Line No.: 11 Column: d

Non-firm transmission service.

Schedule Page: 328.1 Line No.: 12 Column: d

Non-firm transmission service.

Schedule Page: 328.1 Line No.: 13 Column: d

Non-firm transmission service.

Schedule Page: 328.1 Line No.: 14 Column: d

Non-firm transmission service.

Schedule Page: 328.1 Line No.: 15 Column: d

Non-firm transmission service.

Schedule Page: 328.1 Line No.: 16 Column: d

Non-firm transmission service.

Schedule Page: 328.1 Line No.: 17 Column: d

Non-firm transmission service.

Schedule Page: 328.2 Line No.: 1 Column: d

Non-firm transmission service.

Schedule Page: 328.2 Line No.: 2 Column: d

Non-firm transmission service.

Schedule Page: 328.2 Line No.: 3 Column: d

Non-firm transmission service.

Schedule Page: 328.2 Line No.: 4 Column: d

Non-firm transmission service.

Schedule Page: 328.2 Line No.: 5 Column: d

Non-firm transmission service.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e., wheeling of electricity provided to respondent by other electric utilities, cooperatives, municipalities, or other public authorities during the year.
2. In column (a) report each company or public authority that provide 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.
3. Provide in column (a) subheadings and classify transmission service purchased form other utilities as: "Delivered Power to Wheeler" or "Received Power from Wheeler."
4. Report in columns (b) and (c) the total Megawatthours received and delivered by the provider of the transmission service.
5. In columns (d) through (g), report expenses as shown on bills or vouchers rendered to the respondent. In column (d), provide demand charges. In column (e), provide energy charges related to the amount of energy transferred. In column (f), provide 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 (f). Report in column (9) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero ("0") column (g). 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. Provide a total amount in columns (b) through (g) as the last Line. Energy provided by the respondent for the wheeler's transmission tosses should be reported on the Electric Energy Account, Page 401. If the respondent received power from the wheeler, energy provided to account for Losses should be reported on Line 19. Transmission By Others Losses, on Page 401. Otherwise, Losses should be reported on line 27, Total Energy Losses, Page 401.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	TRANSFER OF ENERGY Magawatt-hours Received (b)	Magawatt-hours Delivered (c)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (d)	Energy Charges ($) (e)	Other Charges ($) (f)	Total Cost of Transmission ($) (g)
1	Rcvd Power fr Wheeler						
2	Bonneville Pwr Admin	2,213,202	2,213,202			16,571,676	16,571,676
3	Bonneville Pwr Admin	6,459,479	6,459,479			15,199,762	15,199,762
4	Bonneville Pwr Admin	178,870	178,870			421,132	421,132
5	Bonneville Pwr Admin	-520,858	-520,858		-1,797,705		-1,797,705
6	Bonneville Pwr Admin					5,838,218	5,838,218
7	Montana Power Co.					272,258	272,258
8	Montana Power Co.					-1,262,420	-1,262,420
9	City of Ellensburg	2,017	2,017		25,212		25,212
10	PUD Clallam County					4,021	4,021
11	Avista Energy	70,504	70,504		111,128		111,128
12	Idacorp	100	100		240		240
13	Northwestern Energy	44,579	44,579		207,738		207,738
14	Pacificorp	4,596	4,596		31,269		31,269
15	Portland General Elec	152,928	152,928		363,047		363,047
16	Snohomish Co. PUD #1	269	269		92,769		92,769
	TOTAL	9,567,814	9,567,814		-966,152	38,848,732	37,882,580

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e., wheeling of electricity provided to respondent by other electric utilities, cooperatives, municipalities, or other public authorities during the year.
2. In column (a) report each company or public authority that provide 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.
3. Provide in column (a) subheadings and classify transmission service purchased form other utilities as: "Delivered Power to Wheeler" or "Received Power from Wheeler."
4. Report in columns (b) and (c) the total Megawatthours received and delivered by the provider of the transmission service.
5. In columns (d) through (g), report expenses as shown on bills or vouchers rendered to the respondent. In column (d), provide demand charges. In column (e), provide energy charges related to the amount of energy transferred. In column (f), provide 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 (f). Report in column (9) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero ("0") column (g). 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. Provide a total amount in columns (b) through (g) as the last Line. Energy provided by the respondent for the wheeler's transmission tosses should be reported on the Electric Energy Account, Page 401. If the respondent received power from the wheeler, energy provided to account for Losses should be reported on Line 19. Transmission By Others Losses, on Page 401. Otherwise, Losses should be reported on line 27, Total Energy Losses, Page 401.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
		Magawatt-hours Received (b)	Magawatt-hours Delivered (c)	Demand Charges ($) (d)	Energy Charges ($) (e)	Other Charges ($) (f)	Total Cost of Transmission ($) (g)
1	City of Spokane					-375,520	-375,520
2	Tacoma City Light	31	31		150		150
3	Wasco County PUD					-84,300	-84,300
4							
5							
6							
7	Deliv'd Pwr to Wheeler						
8	Bonneville Power Admin.	962,097	962,097			2,263,905	2,263,905
9							
10							
11							
12							
13							
14							
15							
16							
	TOTAL	9,567,814	9,567,814		-966,152	38,848,732	37,882,580

Schedule Page: 332 Line No.: 2 Column: f

Fixed transmission capacity charges not based on the MWH's wheeled.

Schedule Page: 332 Line No.: 3 Column: f

Fixed transmission capacity charges not based on the MWH's wheeled.

Schedule Page: 332 Line No.: 4 Column: f

Fixed transmission capacity charges not based on the MWH's wheeled.

Schedule Page: 332 Line No.: 6 Column: f

Use of transmission facilites charges.

Schedule Page: 332 Line No.: 7 Column: f

Use of transmission facilites charges.

Schedule Page: 332 Line No.: 8 Column: f

Reimbursement to Puget for wheeling done by Bonneville Power

Schedule Page: 332 Line No.: 10 Column: f

Use of transmission facilites charges.

Schedule Page: 332.1 Line No.: 1 Column: f

Reimbursement to Puget for wheeling done by Bonneville Power

Schedule Page: 332.1 Line No.: 3 Column: f

Reimbursement to Puget for wheeling done by Bonneville Power

Schedule Page: 332.1 Line No.: 8 Column: f

Fixed transmission capacity charges not based on the MWH's wheeled.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	372,785
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	50,097
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	844,860
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6		
7	Board of director fees and expenses	
8	C.W. Bingham	31,129
9	C.W. Cole	453
10	D.P. Beighle	154
11	J.D. Durbin	6,797
12	K.P. Mortimer	4,349
13	P.J. Campbell	45
14	S.G. Narodick	45
15	T. Moriguchi	24,775
16	Deferred Director Fees	162,512
17	Director Stock Plan	103,515
18		
19	Economic Development Council-Seattle/King County-	10,352
20	an organization of public and private interests	
21	working together to foster economic growth in	
22	the Seattle/King County area.	
23		
24	Northwest Energy Coalition - an organiztion to	24,141
25	promote energy efficiency policies, programs and	
26	technologies that foster economic growth and	
27	environmental improvement.	
28		
29	Washington Roundtable - an organization utilizing	14,822
30	the knowledge, creativity and leadership of its	
31	members and their businesses to address the	
32	most serious challenges facing the street.	
33		
34	Western Systems	254,826
35	Western Energy Institute	56,402
36	All other Membership dues	104,631
37		
38	Other Expenses:	
39	Adjacency Study	38,979
40	Audit Expenses	12,429
41	Communications Services	197,764
42	Customer Survey	42,352
43	Treasury Fees & Expenses	354,354
44		
45	Misc. Gen. Exp. - Electric	9,486
46	TOTAL	2,722,054

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in Section A for the year the amounts for: (a) Depreciation Expense (Account 403); (b) Amortization of Limited-Term Electric Plant (Account 404); and (c) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited Term Electric Plant (Acc 404) (c)	Amortization of Other Electric Plant (Acc 405) (d)	Total (e)
1	Intangible Plant		2,627,211		2,627,211
2	Steam Production Plant	19,636,953			19,636,953
3	Nuclear Production Plant				
4	Hydraulic Production Plant-Conventional	10,152,218	289,356		10,441,574
5	Hydraulic Production Plant-Pumped Storage				
6	Other Production Plant	4,512,124	21,585		4,533,709
7	Transmission Plant	7,105,581			7,105,581
8	Distribution Plant	70,413,587			70,413,587
9	General Plant	7,028,504			7,028,504
10	Common Plant-Electric	3,627,185	15,842,794		19,469,979
11	TOTAL	122,476,152	18,780,946		141,257,098

B. Basis for Amortization Charges

Account	Category	Basis for Amortization
404	Leasehold Improvements	Life of Franchise
404	Computer Software	Original estimated useful life
404	Franchise	Life of Franchise
404	White River/Electron Land Rights	40 Years

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
14							
15							
16							
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Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	WUTC Filing Fee	2,593,077		2,593,077	
2					
3	Federal License Fees:				
4	Upper & Lower Baker Project	286,036		286,036	
5	Snoqualmie 1 & 2 Project	249,385		249,385	
6	Electric Hydro Licensing fee	200		200	
7	White River	100,245		100,245	
8					
9	FERC Land Fees				
10	Upper & Lower Baker Project	211,838		211,838	
11					
12	Other FERC Charges				
13	Annual Power License Fees				
14	FERC Regulatory Comm Trading Exp	297,116		297,116	
15					
16					
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46	TOTAL	3,737,897		3,737,897	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Electric	928	2,593,077					1
							2
							3
Electric	928	286,036					4
Electric	928	249,385					5
Electric	928	200					6
Electric	928	100,245					7
							8
							9
Electric	928	211,838					10
							11
							12
Electric	928						13
Electric	928	297,116					14
							15
							16
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		3,737,897					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
(1) Generation
a. hydroelectric
i. Recreation fish and wildlife
ii Other hydroelectric
b. Fossil-fuel steam
c. Internal combustion or gas turbine
d. Nuclear
e. Unconventional generation
f. Siting and heat rejection

(3) Transmission
a. Overhead
b. Underground
(4) Distribution
(5) Environment (other than equipment)
(6) Other (Classify and include items in excess of $5,000.)
(7) Total Cost Incurred
B. Electric, R, D & D Performed Externally:
(1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	NONE	
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
					4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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	5,684,385		
4	Transmission	1,132,557		
5	Distribution	11,379,139		
6	Customer Accounts	10,732,418		
7	Customer Service and Informational	1,275,864		
8	Sales	860,651		
9	Administrative and General	13,684,765		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	44,749,779		
11	Maintenance			
12	Production	2,411,317		
13	Transmission	338,704		
14	Distribution	8,197,760		
15	Administrative and General	511,973		
16	TOTAL Maint. (Total of lines 12 thru 15)	11,459,754		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	8,095,702		
19	Transmission (Enter Total of lines 4 and 13)	1,471,261		
20	Distribution (Enter Total of lines 5 and 14)	19,576,899		
21	Customer Accounts (Transcribe from line 6)	10,732,418		
22	Customer Service and Informational (Transcribe from line 7)	1,275,864		
23	Sales (Transcribe from line 8)	860,651		
24	Administrative and General (Enter Total of lines 9 and 15)	14,196,738		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	56,209,533	606,395	56,815,928
26	Gas			
27	Operation			
28	Production-Manufactured Gas	33,691		
29	Production-Nat. Gas (Including Expl. and Dev.)			
30	Other Gas Supply	311,650		
31	Storage, LNG Terminaling and Processing	13,819		
32	Transmission	108,344		
33	Distribution	10,872,662		
34	Customer Accounts	5,598,521		
35	Customer Service and Informational	460,417		
36	Sales	394,732		
37	Administrative and General	6,314,559		
38	TOTAL Operation (Enter Total of lines 28 thru 37)	24,108,395		
39	Maintenance			
40	Production-Manufactured Gas	97,409		
41	Production-Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission	92,765		
45	Distribution	2,410,638		
46	Administrative and General	284,958		
47	TOTAL Maint. (Enter Total of lines 40 thru 46)	2,885,770		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Total Operation and Maintenance			
49	Production-Manufactured Gas (Enter Total of lines 28 and 40)	131,100		
50	Production-Natural Gas (Including Expl. and Dev.) (Total lines 29,			
51	Other Gas Supply (Enter Total of lines 30 and 42)	311,650		
52	Storage, LNG Terminaling and Processing (Total of lines 31 thru	13,819		
53	Transmission (Lines 32 and 44)	201,109		
54	Distribution (Lines 33 and 45)	13,283,300		
55	Customer Accounts (Line 34)	5,598,521		
56	Customer Service and Informational (Line 35)	460,417		
57	Sales (Line 36)	394,732		
58	Administrative and General (Lines 37 and 46)	6,599,517		
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)	26,994,165	291,216	27,285,381
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	83,203,698	897,611	84,101,309
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	17,003,164	183,432	17,186,596
66	Gas Plant	11,695,154	126,169	11,821,323
67	Other (provide details in footnote):	3,809,428	41,097	3,850,525
68	TOTAL Construction (Total of lines 65 thru 67)	32,507,746	350,698	32,858,444
69	Plant Removal (By Utility Departments)			
70	Electric Plant	914,076	9,861	923,937
71	Gas Plant	87,750	947	88,697
72	Other (provide details in footnote):	1,631,878	17,605	1,649,483
73	TOTAL Plant Removal (Total of lines 70 thru 72)	2,633,704	28,413	2,662,117
74	Other Accounts (Specify, provide details in footnote):			
75	121 Non Utility Property	90,475	976	91,451
76	163 Stores Exp.	2,013,743	21,724	2,035,467
77	182 Regulatory Asset	1,696,071	18,297	1,714,368
78	185 Temporay Facilities	11,686	126	11,812
79	186 Misc. Deferred Debits	1,631,781	17,604	1,649,385
80	Misc. 400 Accounts	1,330,930	14,358	1,345,288
81	143 Accts Receivable Misc. 9265323	468,697	5,056	473,753
82	Joint Venture Expenditures	234,349	2,528	236,877
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	7,477,732	80,669	7,558,401
96	TOTAL SALARIES AND WAGES	125,822,880	1,357,391	127,180,271

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

1 & 2. Common Plant in Service and Accumulated Provision for Depreciation:

Common Plant balances are not allocated to Electric or Gas departments.

Acct	Description	Book Value 12-31-2002	Accumulated Provision for Depreciation
303	Software development	219,332,100	
374	Land & land rights	-	
375	Structures	-	
389	Land & land rights	5,968,620	
390	Structures & improvements	79,280,558	
391	Office furniture & equipment	27,381,316	
393	Stores equipment	10,466	
394	Tools / shop / garage equipment	278,852	
396	Power operated equipment	632,288	
397	Communication equipment	40,679,891	
398	Misc. equipment	97,182	
	Total Common Plant in Service	373,661,273	29,777,315

3. Common Expenses allocated to Electric and Gas departments:

Acct.	Description	Total	Allocated to Electric Dept.	Allocated to Gas Dept.	Basis of Allocation
901	Cust acct. / coll. Supervision	880,252	534,577	345,675	12 month avg. # cust
902	Meter reading	1,161,833	757,515	404,318	Joint Meter Reading
903	Cust rcrds & collect	16,572,104	10,064,239	6,507,865	12 month avg. # cust
905	Misc. cust accts. exp.	(54,372)	(33,020)	(21,352)	12 month avg. # cust
908	Customer assistance	424,193	257,612	166,581	12 month avg. # cust
909	Info & inst. Advertisement	584,599	355,027	229,572	12 month avg. # cust
910	Misc. customer svc & info	98,768	59,982	38,786	12 month avg. # cust
912	Demo & selling exp.	54,917	33,351	21,566	12 month avg. # cust
913	Advertising expenses	-	0	0	12 month avg. # cust
920	Admin. & general salaries	18,304,285	12,631,787	5,672,498	4 factor allocator
921	Office supplies & expense	17,525,705	12,094,489	5,431,216	4 factor allocator
933	Admin. exp. transferred	(212,562)	(146,689)	(65,873)	4 factor allocator
923	Outside services employed	4,751,543	3,279,040	1,472,503	4 factor allocator
924	Property insurance	1,696,353	1,104,156	592,197	Non-production plant
925	Injuries & damage	3,510,846	2,132,137	1,378,709	12 month avg. # cust
926	Employee pensions & benefits	781,546	520,432	261,115	Direct Labor

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

930.1	General advertising	-	0	0	4 factor allocator
930.2	Misc. general expense	2,910,768	2,008,721	902,047	4 factor allocator
931	Rents	3,548,159	2,448,584	1,099,574	4 factor allocator
935	Maint of general plant	4,047,195	2,792,969	1,254,226	4 factor allocator
403	Depreciation	5,256,028	3,627,185	1,628,843	4 factor allocator
404	Amort of LTD term plant	22,957,244	15,842,794	7,114,450	4 factor allocator

Note 1 : The 4 factor allocator is made up of 25% each customer counts, direct labor O&M, classified plant, and T&D expense excluding labor.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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)	19,253,824
3	Steam	4,888,986			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	8,377
5	Hydro-Conventional	1,351,540			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,063,076
7	Other	755,750			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	6,996,276	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	28,803
10	Purchases	19,621,559	27	Total Energy Losses	1,312,323
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	26,666,403
12	Received	2,597,393			
13	Delivered	2,548,825			
14	Net Exchanges (Line 12 minus line 13)	48,568			
15	Transmission For Other (Wheeling)				
16	Received	4,564,763			
17	Delivered	4,564,763			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	26,666,403			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

MONTHLY PEAKS AND OUTPUT

1. 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 in column (b) the system's energy output for each month such that the total on Line 41 matches the total on Line 20.
3. Report in column (c) a monthly breakdown of the Non-Requirements Sales For Resale reported on Line 24. include in the monthly amounts any energy losses associated with the sales so that the total on Line 41 exceeds the amount on Line 24 by the amount of losses incurred (or estimated) in making the Non-Requirements Sales for Resale.
4. Report in column (d) the system's monthly maximum megawatt Load (60-minute integration) associated with the net energy for the system defined as the difference between columns (b) and (c)
5. Report in columns (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	2,371,964	303,676	3,817	28	1900
30	February	2,213,259	396,399	3,750	26	800
31	March	2,645,869	652,738	3,748	20	1900
32	April	2,199,792	538,069	3,130	23	800
33	May	1,994,581	409,461	3,201	7	2200
34	June	1,927,515	488,996	2,610	13	1600
35	July	2,124,429	617,743	2,670	23	1700
36	August	2,053,829	541,840	2,687	13	1600
37	September	1,944,741	484,278	2,677	30	2000
38	October	2,044,187	353,030	3,568	31	800
39	November	2,451,381	643,735	3,520	26	800
40	December	2,694,856	633,111	3,677	18	1900
41	TOTAL	26,666,403	6,063,076			

Schedule Page: 401 Line No.: 29 Column: b

MONTHLY PEAK AND OUTPUT (Continued)

Point Roberts Distribution Lines of
Puget Sound Energy

Line No.	Month	Peak kW	Day of Week	Day of Month	Hour	Type of Reading	Monthly Output (KWH)
1	January	5,026	Unknown	Unknown	Unknown	15 Minutes as	2,227,200
2	February	4,075	"	"	"	recorded on demand	1,896,000
3	March	4,459	"	"	"	attachment to watt	2,006,400
4	April	3,451	"	"	"	hour meter	1,718,400
5	May	3,254	"	"	"		1,358,400
6	June	2,520	"	"	"		1,084,800
7	July	2,525	"	"	"		1,396,800
8	August	2,728	"	"	"		1,276,800
9	September	2,894	"	"	"		1,276,800
10	October	3,283	"	"	"		1,416,000
11	November	3,595	"	"	"		1,636,800
12	December	4,138	"	"	"		2,160,000
13	TOTAL						19,454,400

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 37) and average cost per unit of fuel burned (Line 40) must be consistent with charges to expense accounts 501 and 547 (Line 41) as show on Line 19. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)	Plant Name: *COLSTRIP 1 & 2* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		Semi-Outdoor
3	Year Originally Constructed		1975
4	Year Last Unit was Installed		1976
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	358.37
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	330
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	924403
14	Structures and Improvements	0	44620768
15	Equipment Costs	0	155606837
16	Total Cost	0	201152008
17	Cost per KW of Installed Capacity (line 5)	0.0000	561.2970
18	Production Expenses: Oper, Supv, & Engr	0	116813
19	Fuel	0	5395819
20	Coolants and Water (Nuclear Plants Only)	0	0
21	Steam Expenses	0	1415171
22	Steam From Other Sources	0	0
23	Steam Transferred (Cr)	0	0
24	Electric Expenses	0	91724
25	Misc Steam (or Nuclear) Power Expenses	0	6641050
26	Rents	0	18157
27	Allowances	0	0
28	Maintenance Supervision and Engineering	0	609717
29	Maintenance of Structures	0	444599
30	Maintenance of Boiler (or reactor) Plant	0	4978170
31	Maintenance of Electric Plant	0	475394
32	Maintenance of Misc Steam (or Nuclear) Plant	0	640556
33	Total Production Expenses	0	20827170
34	Expenses per Net KWh	0.0000	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
35	Fuel: Kind (Coal, Gas, Oil, or Nuclear)				Coal	Gas	Oil
36	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)				Tons	MCF	Bbl.
37	Quantity (units) of Fuel Burned	0	0	0	0	0	0
38	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
39	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
40	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
43	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 37) and average cost per unit of fuel burned (Line 40) must be consistent with charges to expense accounts 501 and 547 (Line 41) as show on Line 19. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *WHITEHORN 2 & 3* (b)			Plant Name: *FREDERICKSON* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Outdoor		
3	Year Originally Constructed	1981			1981		
4	Year Last Unit was Installed	1981			1981		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	177.80			177.80		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	150			150		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	3			3		
12	Net Generation, Exclusive of Plant Use - KWh	14613700			3653800		
13	Cost of Plant: Land and Land Rights	0			796631		
14	Structures and Improvements	0			2143706		
15	Equipment Costs	0			28846861		
16	Total Cost	0			31787198		
17	Cost per KW of Installed Capacity (line 5)	0.0000			178.7806		
18	Production Expenses: Oper, Supv, & Engr	44916			100461		
19	Fuel	876414			160403		
20	Coolants and Water (Nuclear Plants Only)	0			0		
21	Steam Expenses	0			0		
22	Steam From Other Sources	0			0		
23	Steam Transferred (Cr)	0			0		
24	Electric Expenses	84550			90683		
25	Misc Steam (or Nuclear) Power Expenses	34142			78430		
26	Rents	4271791			0		
27	Allowances	0			0		
28	Maintenance Supervision and Engineering	1015			15759		
29	Maintenance of Structures	14475			96241		
30	Maintenance of Boiler (or reactor) Plant	0			0		
31	Maintenance of Electric Plant	1010098			66519		
32	Maintenance of Misc Steam (or Nuclear) Plant	18150			4131		
33	Total Production Expenses	6355551			612627		
34	Expenses per Net KWh	0.4349			0.1677		
35	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Gas	Oil		Gas	Oil
36	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		MCF	Bbl.		MCF	Bbl.
37	Quantity (units) of Fuel Burned	0	180907	150	0	46702	401
38	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1035000	141000	0	1035000	141000
39	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	3.910	0.000	0.000	2.790	0.000
40	Average Cost of Fuel per Unit Burned	0.000	3.910	44.250	0.000	2.790	33.250
41	Average Cost of Fuel Burned per Million BTU	0.000	3.780	7.470	0.000	2.690	5.610
42	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.007	0.001	0.000	0.036	0.089
43	Average BTU per KWh Net Generation	0.000	1929.000	90.000	0.000	13281.000	15861.000

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Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 37) and average cost per unit of fuel burned (Line 40) must be consistent with charges to expense accounts 501 and 547 (Line 41) as show on Line 19. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Total Cost	0			0		
17	Cost per KW of Installed Capacity (line 5)	0.0000			0.0000		
18	Production Expenses: Oper, Supv, & Engr	0			0		
19	Fuel	0			0		
20	Coolants and Water (Nuclear Plants Only)	0			0		
21	Steam Expenses	0			0		
22	Steam From Other Sources	0			0		
23	Steam Transferred (Cr)	0			0		
24	Electric Expenses	0			0		
25	Misc Steam (or Nuclear) Power Expenses	0			0		
26	Rents	0			0		
27	Allowances	0			0		
28	Maintenance Supervision and Engineering	0			0		
29	Maintenance of Structures	0			0		
30	Maintenance of Boiler (or reactor) Plant	0			0		
31	Maintenance of Electric Plant	0			0		
32	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
33	Total Production Expenses	0			0		
34	Expenses per Net KWh	0.0000			0.0000		
35	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
36	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
37	Quantity (units) of Fuel Burned	0	0	0	0	0	0
38	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
39	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
40	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
43	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 37) and average cost per unit of fuel burned (Line 40) must be consistent with charges to expense accounts 501 and 547 (Line 41) as show on Line 19. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Total Cost	0			0		
17	Cost per KW of Installed Capacity (line 5)	0.0000			0.0000		
18	Production Expenses: Oper, Supv, & Engr	0			0		
19	Fuel	0			0		
20	Coolants and Water (Nuclear Plants Only)	0			0		
21	Steam Expenses	0			0		
22	Steam From Other Sources	0			0		
23	Steam Transferred (Cr)	0			0		
24	Electric Expenses	0			0		
25	Misc Steam (or Nuclear) Power Expenses	0			0		
26	Rents	0			0		
27	Allowances	0			0		
28	Maintenance Supervision and Engineering	0			0		
29	Maintenance of Structures	0			0		
30	Maintenance of Boiler (or reactor) Plant	0			0		
31	Maintenance of Electric Plant	0			0		
32	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
33	Total Production Expenses	0			0		
34	Expenses per Net KWh	0.0000			0.0000		
35	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
36	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
37	Quantity (units) of Fuel Burned	0	0	0	0	0	0
38	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
39	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
40	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
43	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 24 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 31, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *COLSTRIP 3 & 4* (d)			Plant Name: *ENCOGEN* (e)			Plant Name: (f)			Line No.
		Steam			Steam				1
		Semi-Outdoor			Outdoor				2
		1984			1993				3
		1986			1993				4
		389.03			170.00			0.00	5
		0			0			0	6
		0			0			0	7
		0			0			0	8
		370			160			0	9
		0			0			0	10
		0			21			0	11
		0			941557290			0	12
		2641060			1051000			0	13
		127233774			6416121			0	14
		328352768			146440820			0	15
		458227602			153907941			0	16
		1177.8721			905.3408			0.0000	17
		82176			399104			0	18
		5955566			29821645			0	19
		0			0			0	20
		757985			208259			0	21
		0			0			0	22
		0			0			0	23
		86778			309210			0	24
		3473506			111702			0	25
		71059			5380			0	26
		0			0			0	27
		292421			471157			0	28
		493978			67843			0	29
		3249832			497396			0	30
		1892310			1016610			0	31
		445427			209401			0	32
		16801038			33117707			0	33
		0.0000			0.0352			0.0000	34
Coal	Gas	Oil		Gas	Oil		Gas	Oil	35
Tons	MCF	Bbl.		MCF	Bbl.		MCF	Bbl.	36
0	0	0	0	8128364	595	0	0	0	37
0	0	0	0	1035000	141000	0	0	0	38
0.000	0.000	0.000	0.000	3.390	0.000	0.000	0.000	0.000	39
0.000	0.000	0.000	0.000	3.390	7.760	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	3.280	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.029	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	8935.000	0.000	0.000	0.000	0.000	43

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 24 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 31, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *FREDONIA 1 & 2* (d)	Plant Name: *FREDONIA 3 & 4* (e)	Plant Name: (f)	Line No.
Gas Turbine	Gas Turbine		1
Outdoor	Outdoor		2
1984	2001		3
1984	2001		4
247.20	124.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
210	108	0	9
0	0	0	10
2	3	0	11
10995800	45908100	0	12
1281059	0	0	13
3430686	0	0	14
46390804	0	0	15
51102549	0	0	16
206.7255	0.0000	0.0000	17
83047	652	0	18
20666201	30360721	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
123868	93103	0	24
217091	54075	0	25
0	5045420	0	26
0	0	0	27
5217	1325	0	28
70353	0	0	29
0	0	0	30
923019	173027	0	31
5111	9492	0	32
22093907	35737815	0	33
2.0093	0.7785	0.0000	34

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
	Gas	Oil		Gas	OIl				35
	MCF	Bbl.		MCF	Bbl.				36
0	0	0	0	556618	7782	0	0	0	37
0	1035000	141000	0	1035000	141000	0	0	0	38
0.000	0.000	0.000	0.000	2.890	0.000	0.000	0.000	0.000	39
0.000	0.000	0.000	0.000	2.890	38.950	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	2.800	6.580	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.031	0.070	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	11114.000	10603.000	0.000	0.000	0.000	43

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 24 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 31, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
		0.00			0.00			0.00	5
		0			0			0	6
		0			0			0	7
		0			0			0	8
		0			0			0	9
		0			0			0	10
		0			0			0	11
		0			0			0	12
		0			0			0	13
		0			0			0	14
		0			0			0	15
		0			0			0	16
		0.0000			0.0000			0.0000	17
		0			0			0	18
		0			0			0	19
		0			0			0	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		0			0			0	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		0			0			0	30
		0			0			0	31
		0			0			0	32
		0			0			0	33
		0.0000			0.0000			0.0000	34
									35
									36
0	0	0	0	0	0	0	0	0	37
0	0	0	0	0	0	0	0	0	38
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 24 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 31, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
		0.00			0.00			0.00	5
		0			0			0	6
		0			0			0	7
		0			0			0	8
		0			0			0	9
		0			0			0	10
		0			0			0	11
		0			0			0	12
		0			0			0	13
		0			0			0	14
		0			0			0	15
		0			0			0	16
		0.0000			0.0000			0.0000	17
		0			0			0	18
		0			0			0	19
		0			0			0	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		0			0			0	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		0			0			0	30
		0			0			0	31
		0			0			0	32
		0			0			0	33
		0.0000			0.0000			0.0000	34
									35
									36
0	0	0	0	0	0	0	0	0	37
0	0	0	0	0	0	0	0	0	38
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43

Schedule Page: 402 Line No.: 5 Column: c

Jointly owned. Amounts on Line 5 and 9, Column (c) represent 50% of Rated Capacity of 716,742 Kw.

Schedule Page: 402 Line No.: 5 Column: d

Jointly owned. Amounts on Line 5 and 9, Column (d) represent 25% of Rated Capacity of 1,556,000Kw.

Schedule Page: 402 Line No.: 6 Column: c

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 6 Column: d

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 7 Column: c

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 7 Column: d

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 9 Column: c

Jointly owned. Amounts on Line 5 and 9, Column (c) represent 50% of Rated Capacity of 716,742 KW.

Schedule Page: 402 Line No.: 9 Column: d

Jointly owned. Amounts on Line 5 and 9, Column (d) represent 25% of Rated Capacity of 1,556,000KW.

Schedule Page: 402 Line No.: 11 Column: c

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 11 Column: d

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 12 Column: c

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 12 Column: d

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 34 Column: c

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 34 Column: d

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402.1 Line No.: 13 Column: b

Generation unit is leased.

Schedule Page: 402.1 Line No.: 13 Column: e

Generation unit is leased.

Schedule Page: 402.1 Line No.: 14 Column: b

Generation unit is leased.

Schedule Page: 402.1 Line No.: 14 Column: e

Generation unit is leased.

Schedule Page: 402.1 Line No.: 15 Column: b

Generation unit is leased.

Schedule Page: 402.1 Line No.: 15 Column: e

Generation unit is leased.

Schedule Page: 402.1 Line No.: 16 Column: b

Generation unit is leased.

Schedule Page: 402.1 Line No.: 16 Column: e

Generation unit is leased.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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FOOTNOTE DATA

Schedule Page: 402.1 Line No.: 17 Column: b

Generation unit is leased.

Schedule Page: 402.1 Line No.: 17 Column: e

Generation unit is leased.

Schedule Page: 402 Line No.: 37 Column: c1

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 37 Column: d1

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 38 Column: c1

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 38 Column: d1

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 39 Column: c1

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 39 Column: d1

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 40 Column: c1

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 40 Column: d1

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 41 Column: c1

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 41 Column: d1

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 42 Column: c1

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 42 Column: d1

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 43 Column: c1

Plants are operated by PP&L Global. Information will be reported by them.

Schedule Page: 402 Line No.: 43 Column: d1

Plants are operated by PP&L Global. Information will be reported by them.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plan, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2150 Plant Name: LOWER BAKER (b)	FERC Licensed Project No. 2150 Plant Name: UPPER BAKER (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1925	1959
4	Year Last Unit was Installed	1960	1959
5	Total installed cap (Gen name plate Rating in MW)	79.00	90.70
6	Net Peak Demand on Plant-Megawatts (60 minutes)	79	106
7	Plant Hours Connect to Load	6,746	3,710
8	Net Plant Capability (in megawatts)	0	0
9	(a) Under Most Favorable Oper Conditions	79	108
10	(b) Under the Most Adverse Oper Conditions	79	108
11	Average Number of Employees	20	2
12	Net Generation, Exclusive of Plant Use - Kwh	400,861,320	353,106,046
13	Cost of Plant	0	0
14	Land and Land Rights	698,457	1,262,830
15	Structures and Improvements	2,882,305	4,626,618
16	Reservoirs, Dams, and Waterways	12,635,881	45,557,825
17	Equipment Costs	13,431,186	11,320,386
18	Roads, Railroads, and Bridges	66,170	645,095
19	TOTAL cost (Total of 14 thru 18)	29,713,999	63,412,754
20	Cost per KW of Installed Capacity (line 5)	376.1266	699.1483
21	Production Expenses	0	0
22	Operation Supervision and Engineering	108,931	75,103
23	Water for Power	0	0
24	Hydraulic Expenses	142,965	446,144
25	Electric Expenses	151,647	145,501
26	Misc Hydraulic Power Generation Expenses	493,276	143,329
27	Rents	0	0
28	Maintenance Supervision and Engineering	28,706	33,950
29	Maintenance of Structures	122,996	133,657
30	Maintenance of Reservoirs, Dams, and Waterways	17,875	38,767
31	Maintenance of Electric Plant	96,169	53,895
32	Maintenance of Misc Hydraulic Plant	175,544	291,909
33	Total Production Expenses (total 22 thru 32)	1,338,109	1,362,255
34	Expenses per net KWh	0.0033	0.0039

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plan, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2494 Plant Name: WHITE RIVER (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run of River	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1912	
4	Year Last Unit was Installed	1924	
5	Total installed cap (Gen name plate Rating in MW)	70.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	60	0
7	Plant Hours Connect to Load	5,339	0
8	Net Plant Capability (in megawatts)	0	0
9	(a) Under Most Favorable Oper Conditions	70	0
10	(b) Under the Most Adverse Oper Conditions	70	0
11	Average Number of Employees	20	0
12	Net Generation, Exclusive of Plant Use - Kwh	228,229,000	0
13	Cost of Plant	0	0
14	Land and Land Rights	7,931,071	0
15	Structures and Improvements	1,920,912	0
16	Reservoirs, Dams, and Waterways	41,678,251	0
17	Equipment Costs	9,022,654	0
18	Roads, Railroads, and Bridges	673,824	0
19	TOTAL cost (Total of 14 thru 18)	61,226,712	0
20	Cost per KW of Installed Capacity (line 5)	874.6673	0.0000
21	Production Expenses	0	0
22	Operation Supervision and Engineering	146,393	0
23	Water for Power	0	0
24	Hydraulic Expenses	132,252	0
25	Electric Expenses	441,973	0
26	Misc Hydraulic Power Generation Expenses	151,109	0
27	Rents	0	0
28	Maintenance Supervision and Engineering	33,641	0
29	Maintenance of Structures	112,954	0
30	Maintenance of Reservoirs, Dams, and Waterways	307,898	0
31	Maintenance of Electric Plant	244,112	0
32	Maintenance of Misc Hydraulic Plant	285,137	0
33	Total Production Expenses (total 22 thru 32)	1,855,469	0
34	Expenses per net KWh	0.0081	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plan, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)	0	0
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant	0	0
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	TOTAL cost (Total of 14 thru 18)	0	0
20	Cost per KW of Installed Capacity (line 5)	0.0000	0.0000
21	Production Expenses	0	0
22	Operation Supervision and Engineering	0	0
23	Water for Power	0	0
24	Hydraulic Expenses	0	0
25	Electric Expenses	0	0
26	Misc Hydraulic Power Generation Expenses	0	0
27	Rents	0	0
28	Maintenance Supervision and Engineering	0	0
29	Maintenance of Structures	0	0
30	Maintenance of Reservoirs, Dams, and Waterways	0	0
31	Maintenance of Electric Plant	0	0
32	Maintenance of Misc Hydraulic Plant	0	0
33	Total Production Expenses (total 22 thru 32)	0	0
34	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plan, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)	0	0
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant	0	0
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	TOTAL cost (Total of 14 thru 18)	0	0
20	Cost per KW of Installed Capacity (line 5)	0.0000	0.0000
21	Production Expenses	0	0
22	Operation Supervision and Engineering	0	0
23	Water for Power	0	0
24	Hydraulic Expenses	0	0
25	Electric Expenses	0	0
26	Misc Hydraulic Power Generation Expenses	0	0
27	Rents	0	0
28	Maintenance Supervision and Engineering	0	0
29	Maintenance of Structures	0	0
30	Maintenance of Reservoirs, Dams, and Waterways	0	0
31	Maintenance of Electric Plant	0	0
32	Maintenance of Misc Hydraulic Plant	0	0
33	Total Production Expenses (total 22 thru 32)	0	0
34	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plan, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)	0	0
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant	0	0
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	TOTAL cost (Total of 14 thru 18)	0	0
20	Cost per KW of Installed Capacity (line 5)	0.0000	0.0000
21	Production Expenses	0	0
22	Operation Supervision and Engineering	0	0
23	Water for Power	0	0
24	Hydraulic Expenses	0	0
25	Electric Expenses	0	0
26	Misc Hydraulic Power Generation Expenses	0	0
27	Rents	0	0
28	Maintenance Supervision and Engineering	0	0
29	Maintenance of Structures	0	0
30	Maintenance of Reservoirs, Dams, and Waterways	0	0
31	Maintenance of Electric Plant	0	0
32	Maintenance of Misc Hydraulic Plant	0	0
33	Total Production Expenses (total 22 thru 32)	0	0
34	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: ELECTRON (d)	FERC Licensed Project No. 2493 Plant Name: SNOQUALMIE FALLS #1 (e)	FERC Licensed Project No. 2493 Plant Name: SNOQUALMIE FALLS #2 (f)	Line No.
Run of River	Run of River	Run of River	1
Conventional	Conventional	Conventional	2
1904	1898	1910	3
1927	1905	1957	4
26.00	11.90	32.50	5
0	7	34	6
8,573	4,004	8,250	7
0	0	0	8
26	13	36	9
26	13	36	10
20	3	0	11
117,391,700	59,184,400	192,767,600	12
0	0	0	13
2,321,932	32,520	0	14
2,313,521	3,051,914	645,855	15
41,742,427	218,386	1,179,903	16
3,390,560	1,226,255	3,353,715	17
492,607	39,895	27,666	18
50,261,047	4,568,970	5,207,139	19
1,933.1172	383.9471	160.2197	20
0	0	0	21
94,160	36,382	31,977	22
0	0	0	23
500,882	11,936	21,776	24
139,385	99,548	90,055	25
203,132	48,835	18,337	26
0	0	0	27
11,237	35,698	24,285	28
136,536	14,859	10,489	29
227,150	23,976	58,093	30
160,295	147,049	169,309	31
303,156	205,332	13,972	32
1,775,933	623,615	438,293	33
0.0151	0.0105	0.0023	34

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0.0000	0.0000	0.0000	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0.0000	0.0000	0.0000	34

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0.0000	0.0000	0.0000	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0.0000	0.0000	0.0000	34

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0.0000	0.0000	0.0000	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0.0000	0.0000	0.0000	34

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0.0000	0.0000	0.0000	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0.0000	0.0000	0.0000	34

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Total cost (total 13 thru 19)	
21	Cost per KW of installed cap (line 20/line4)	
22	Production Expenses	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Pumped Storage Expenses	
26	Electric Expenses	
27	Misc Pumped Storage Power generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Pumped Storage Plant	
34	Production Exp Before Pumping Exp (23 thru 33)	
35	Pumping Expenses	
36	Total Production Exp (total 34 and 35)	
37	Expenses per KWh (line 36/line 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 35 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 35, 36 and 37 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
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			18
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			20
			21
			22
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			32
			33
			34
			35
			36
			37

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	HYDRO					
2						
3	Skookumchuck	1990	0.70			1,181,113
4						
5						
6	INTERNATIONAL COMBUSTION					
7	Crystal Mountain	1969	2.75		18	589,683
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
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46						

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost Per MW Inst Capacity (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
16,873,043				Run-of-River		3
						4
						5
						6
214,430	36,871	7,284	6,318	Diesel	827	7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
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						45
						46

FOOTNOTE DATA

Schedule Page: 410   Line No.: 3   Column: c

Plant is jointly owned. Amount represents 7% of installed capacity of 0.98 MW.

Schedule Page: 410   Line No.: 3   Column: d

Plant is operated by TransAlta energy. Such information will be reported by them.

Schedule Page: 410   Line No.: 3   Column: e

Plant is operated by TransAlta energy. Such information will be reported by them.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Colstrip #1A	Broadview	500.00	500.00	SCST	112.70		1
2	Colstrip #1B	Broadview	500.00	500.00	SCST	115.90		1
3	Broadview #1	Townsend	500.00	500.00	SCST	133.40		1
4	Broadview #2	Townsend	500.00	500.00	SCST	133.40		1
5	3rd AC Pacific Intertie		500.00	500.00				
6	500kV Tot.							
7								
8	BPA Custer - BPA Murray	Sedro Woolley Sub	230.00	230.00	WHF	0.18		1
9	BPA Covington Sub	White River Sub #1	230.00	230.00	DCST	0.60		1
10	BPA Covington Sub	White River Sub #2	230.00	230.00	DCST	9.24		1
11	BPA Custer Sub	Portal Way Sub	230.00	230.00	WHF	0.06		1
12	BPA Maple Valley Sub	Sammamish Sub	230.00	230.00	DCST	32.42		1
13	BPA Maple Valley Sub	Talbot Hill Sub #1	230.00	230.00	SCST	0.18		1
14	BPA Maple Valley Sub	Talbot Hill Sub #2	230.00	230.00	SCST	0.15		1
15	BPA Monroe Sub	Sammamish Sub	230.00	230.00	SCST/DCST	8.12		1
16	BPA Sno.-BPA Monroe	Horse Ranch Sub	230.00	230.00	DCST, WHF	3.84		1
17	Sedro Woolley Sub	SCL Bothell Sub	230.00	230.00	WHF	48.94		1
18	S. Woolley - SCL Bothel Sub	Horse Ranch Sub	230.00	230.00	WHF	0.48		1
19	Christopher Sub	O'Brien Sub	230.00	230.00	DCST	4.75		1
20	Rocky Reach	Cascade	230.00	230.00	SCST, WHF	57.29		1
21	Cascade	White River	230.00	230.00	SCST, WHF	68.99		1
22	SCL Bothell Sub	Sammamish Sub	230.00	230.00	WHF	13.39		1
23	Sedro Woolley Sub	March Point Sub	230.00	230.00	SWP/DCST	22.87		1
24	Talbot Hill Sub	O'Brien Sub #3	230.00	230.00	DCST	7.22		2
25	White River Sub	BPA Olympia Sub	230.00	230.00	DCST	0.42		1
26	BPA Bellingham	Sedro Wolley	230.00	230.00	DCST	25.00		1
27	Talbot	Berrydale	230.00	230.00	DCST	8.50		2
28	230 kV Tot.							
29								
30	115 kV Tot.		115.00	115.00	SP-W, WHF,	60.21		1
31					St Tower and			
32					Single Wood			
33								
34								
35								
36					TOTAL	868.25		27

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
4-795 ACSR								1
4-795 ACSR								2
4-795 ACSR								3
4-795 ACSR								4
								5
	1,753,427	114,475,275	116,228,702					6
								7
795 ACSR								8
1272 ACSR								9
2-1272 ACSR								10
795 ACSR								11
1780 ACSR								12
2-1780 ACSR								13
2-1780 ACSR								14
1780 ACSR								15
1272 ACSR								16
2-795 ACSR								17
1272 ACSR								18
1272 ACSR								19
1272 ACSR								20
1272 ACSR								21
795 ACSR								22
397.5 ACSR								23
1780 ACSR								24
795 ACSR								25
1.6" AACTW								26
2-1590 ACSR								27
	3,987,794	72,528,744	76,516,538					28
								29
VARIED	109,166	2,607,413	2,716,579					30
								31
								32
								33
								34
				2,111,733	1,402,533	148,334	3,662,600	35
	5,850,387	189,611,432	195,461,819	2,111,733	1,402,533	148,334	3,662,600	36

Schedule Page: 422 Line No.: 1 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 2 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 3 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 4 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 5 Column: a

Facilities are solely owned by the Bonneville Power Administration. Respondent has secured a life-of-facilities capacity ownership interest and will be responsible for its share of plant costs and expenses.

Schedule Page: 422 Line No.: 8 Column: a

Certain Northern Intertie facilities are owned by BPA and PSE. Additionally, PSE has capacity ownership rights in the facilities owned by BPA pursuant to the terms of a life-of-facilities agreement. Each party maintains its own facilities at the party's expense.

Schedule Page: 422 Line No.: 16 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 26 Column: a

Same as footnote immediately above.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	NO ADDITIONS IN 2002						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
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33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST				Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Total (o)	No.
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
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								35
								36
								37
								38
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								40
								41
								42
								43
								44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TRANSMISSION SUBSTATIONS:				
2	Berrydale	T U	230.00	117.87	
3	Cascade - West of Cle Elum	T U	230.00	115.00	
4	Cascade - West of Cle Elum	T U	52.50	14.40	
5	Fredonia - West of Mt Vernon	T U	230.00	13.20	
6	Fredonia - West of Mt Vernon	T U	115.00	13.20	
7	Fredonia - West of Mt Vernon	T U	115.00	13.20	
8	March Point - Southeast of Anacortes	T U	230.00	115.00	
9	March Point - Southeast of Anacortes	T U	110.00	55.00	
10	March Point - Southeast of Anacortes	T U	54.00	7.00	
11	March Point - Southeast of Anacortes	T U	53.75	7.20	
12	O'Brien - Southeast of Kent	T U	230.00	115.00	
13	Portal Way - North of Ferndale	T U	230.00	117.87	
14	Sammamish	T U	230.00	115.00	
15	Sammamish	T U	230.00	117.87	
16	Sammamish	T U	115.00	36.20	
17	Sedro Wooley	T U	230.00	115.00	
18	Sedro Wooley	T U	110.00	55.00	
19	Sedro Wooley	T U	53.75	7.20	
20	Talbot Hill	T U	230.00	117.87	
21	Talbot Hill	T U	230.00	115.00	
22	Tono - East of Centralia	T U	525.00	117.90	
23	White River (TRAN)	T A	230.00	115.00	
24	White River (TRAN)	T A	115.00	55.00	
25	White River (TRAN)	T A	53.75	7.20	
26	TOTAL TRANSMISSION STATIONS		4232.75	1678.18	
27					
28	DISTRIBUTION SUBSTATIONS:				
29	Airport - South of Olympia	D U	115.00	13.09	
30	Alger	D U	115.00	13.09	
31	Anacortes	D U	115.00	13.09	
32	Anacortes Pump	D U	53.75	7.20	
33	Anacortes Pump	D U	115.00	4.36	
34	Arco Central	D U	115.00	13.09	
35	Arco North	D U	115.00	13.09	
36	Arco South	D U	115.00	13.09	
37	Asbury - McMicken	D U	115.00	13.09	
38	Avondale - Redmond	D U	115.00	13.09	
39	Baker River SW	D U	53.81	13.09	
40	Baker River SW	D U	110.00	55.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation		VOLTAGE (In MVa)		
				Primary	Secondary	Tertiary
	(a)	(b)		(c)	(d)	(e)
1	Baker River - Lower Gen.	D	U	115.00	13.20	
2	Baker River - Upper Gen.	D	U	13.20	2.40	
3	Baker River - Upper Gen.	D	U	13.20	7.20	
4	Baker River - Upper Gen.	D	U	115.00	13.20	
5	Bakerview - North of Bellingham	D	U	115.00	13.09	
6	Baldi	D	U	230.00	13.09	
7	Barnes Lake - Tumwater	D	U	115.00	13.09	
8	Bellingham	D	U	53.75	7.20	
9	Bellingham	D	U	110.00	55.00	
10	Bellingham	D	U	110.00	55.00	
11	Bellis	D	U	53.96	13.80	
12	Belmore - Federal Way	D	U	115.00	13.09	
13	Big Rock - East of Mount Vernon	D	U	115.00	13.09	
14	Birch Bay	D	U	115.00	13.09	
15	Black Diamond	D	U	115.00	13.09	
16	Blaine	D	U	115.00	13.09	
17	Blumaer - Tenino	D	U	115.00	13.09	
18	Bonney Lake	D	U	115.00	13.09	
19	Bow Lake -East Of Sea-Tac Airport	D	U	115.00	13.09	
20	Bow Lake	D	U	117.87	13.09	
21	Bow Lake	D	U	117.87	13.09	
22	Bremerton	D	U	115.00	13.09	
23	Bremerton	D	U	13.80	4.50	
24	Bridle Trails	D	U	115.00	13.09	
25	Britton - Bellingham	D	U	115.00	13.09	
26	Brooks Hill	D	U	115.00	13.09	
27	Buckley	D	U	53.81	13.09	
28	Bucklin Hill - Silverdale	D	U	115.00	13.09	
29	Burlington	D	U	115.00	13.09	
30	Burrows Bay - Anacortes	D	U	115.00	13.09	
31	Cambridge	D	U	115.00	13.09	
32	Capitol - Olympia	D	U	55.00	13.80	
33	Carolina - Bellingham	D	U	115.00	13.09	
34	Cedarhurst - North of Puyallup	D	U	115.00	13.09	
35	Center - Bellevue	D	U	115.00	13.09	
36	Central Kitsap (CK)	D	U	115.00	13.09	
37	Chambers - Southeast of Olympia	D	U	115.00	13.09	
38	Chico - West of Bremerton	D	U	115.00	13.09	
39	Chico - West of Bremerton	D	U	34.50	12.50	
40	Christensens Corner	D	U	115.00	13.09	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Clay Creek	D U	53.75	7.20	
2	Clay Creek	D U	52.50	6.90	
3	Cle Elum	D U	230.00	36.20	
4	Clover Valley - Oak Harbor	D U	115.00	13.09	
5	Clyde Hill - Bellevue	D U	115.00	13.09	
6	Clymer	D U	115.00	13.09	
7	College - Bellevue	D U	115.00	13.09	
8	Cottage Brook - North of Redmond	D U	115.00	13.09	
9	Coupeville	D U	115.00	13.09	
10	Crescent Harbor - Oak Harbor	D U	115.00	13.09	
11	Crestwood - Kirkland	D U	115.00	13.09	
12	Crystal Mountain Gen.	D U	12.47	4.16	
13	Cumberland	D U	53.81	13.09	
14	Custer	D U	115.00	13.09	
15	Decatur - Olympia	D U	115.00	13.09	
16	Des Moines	D U	115.00	13.09	
17	Dieringer - White River	D U	115.00	13.09	
18	Discovery Bay	D U	67.00	7.00	
19	Discovery Bay	D U	66.00	11.95	
20	Discovery Bay	D U	67.00	12.00	
21	Dupont	D U	115.00	13.09	
22	Duvall	D U	117.87	13.09	
23	Earlington - West of Renton	D U	115.00	13.09	
24	East Port Orchard	D U	115.00	13.09	
25	East Valley - North of Kent	D U	115.00	13.09	
26	Eastgate	D U	115.00	13.09	
27	Easton	D U	115.00	13.09	
28	Edgewood - East of Melton	D U	115.00	13.09	
29	Eld Inlet - West of Olympia	D U	115.00	13.09	
30	Electron Gen. Station	D U	115.00	2.30	
31	Electron Heights	D U	55.00	14.00	
32	Electron Heigths	D U	55.00	14.40	
33	Electron Heights	D U	110.00	55.00	
34	Ellingson - South of Auburn	D U	115.00	13.09	
35	Encogen Gen. Station	D U	115.00	13.40	
36	Encogen Gen. Station	D U	115.00	13.40	
37	Enumclaw	D U	115.00	13.09	
38	Evergreen - Redmond	D U	115.00	13.09	
39	Faber - Oak Harbor	D U	115.00	13.09	
40	Factoria - East of Bellevue	D U	115.00	13.09	

SUBSTATIONS

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Fairchild - South of Puyallup	D U	115.00	13.09	
2	Fairchild	D U	117.88	13.09	
3	Fairwood - Southeast of Renton	D U	115.00	13.09	
4	Falcon	D U	117.88	13.09	
5	Fall City	D U	115.00	13.09	
6	Fern Hill	D U	52.50	12.47	
7	Fernwood - Southwest of Port Orchard	D U	115.00	13.09	
8	Fragaria	D U	115.00	13.09	
9	Fredrickson	D U	115.00	13.20	
10	Fredrickson Gen. Station	D U	13.80	0.48	
11	Fredrickson Gen. Station	D U	13.80	4.16	
12	Fredonia Gen. Station	D U	13.80	4.16	
13	Fredonia Gen. Station	D U	13.80	0.48	
14	Freeland	D U	115.00	13.09	
15	Freeway - West of Kent	D U	115.00	13.09	
16	Friendly Grove - North of Olympia	D U	53.81	13.09	
17	Fruitland - Puyallup	D U	115.00	13.09	
18	Fryar	D U	12.47	4.16	
19	Garadella - South of Sumner	D U	115.00	13.09	
20	Glacier	D U	52.50	12.47	
21	Goodes Corner - Issaquah	D U	115.00	13.09	
22	Grady - Renton	D U	115.00	36.20	
23	Gravelly Lake	D U	115.00	13.09	
24	Greenbank	D U	115.00	13.09	
25	Greenwater	D U	34.50	12.47	
26	Greenwater	D U	52.50	12.47	
27	Greenwater	D U	52.50	12.47	
28	Griffin - West of Olympia	D U	115.00	13.09	
29	Hamilton	D U	53.81	13.09	
30	Hamilton	D U	115.00	13.09	
31	Hannegan - South of Lynden	D U	115.00	13.09	
32	Happy Valley - Bellingham	D U	115.00	13.09	
33	Harvest - Kent	D U	115.00	13.09	
34	Harvest - Kent	D U	117.88	13.09	
35	Hastings - Port Townsend	D U	115.00	13.09	
36	Hazelwood	D U	115.00	13.09	
37	Hemlock - South of Puyallup	D U	115.00	13.09	
38	Hickox - South of Mount Vernon	D U	115.00	13.09	
39	Highlands - Renton	D U	115.00	13.09	
40	Hillcrest	D U	115.00	13.09	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)		VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Hobart	D	U	115.00	13.09	
2	Holden - West of Gravel Lake	D	U	115.00	13.09	
3	Hollywood - East of Woodinville	D	U	115.00	13.09	
4	Houghton - Kirkland	D	U	115.00	13.09	
5	Hyak	D	U	115.00	13.09	
6	Inglewood - Bothell	D	U	115.00	13.09	
7	Interlaken - Southwest of Redmond	D	U	115.00	13.09	
8	Irondale - South of Port Townsend	D	U	115.00	13.09	
9	Johnson Hill - East of Olympia	D	U	115.00	13.09	
10	Juanita - North of Kirkland	D	U	115.00	13.09	
11	Kapowsin	D	U	115.00	13.09	
12	Kearney Street - Port Townsend	D	U	115.00	13.09	
13	Kendall - Maple Falls	D	U	115.00	53.81	
14	Kendall - Maple Falls	D	U	52.50	13.80	
15	Kenilworth - South of Redmond	D	U	115.00	13.09	
16	Kenmore	D	U	115.00	13.09	
17	Kent	D	U	115.00	13.09	
18	Kittitas	D	U	115.00	13.09	
19	Kitts Corner - South of Federal Way	D	U	115.00	13.09	
20	Klahanie	D	U	230.00	13.09	
21	Krain Corner	D	U	115.00	52.36	
22	Krain Corner	D	U	115.00	13.09	
23	Labounty - Southeast of Ferndale	D	U	115.00	13.09	
24	Lacey	D	U	115.00	13.09	
25	Lake Hills - Bellevue	D	U	115.00	13.09	
26	Lake Leota - Northeast of Woodinville	D	U	115.00	13.09	
27	Lake Louise - East of Bellingham	D	U	115.00	13.09	
28	Lake McDonald - East of Renton	D	U	115.00	13.09	
29	Lake Meridian	D	U	115.00	13.09	
30	Lake Tapps	D	U	53.96	13.81	
31	Lake Wilderness	D	U	115.00	13.09	
32	Lakota - West of Federal Way	D	U	115.00	13.09	
33	Langley - South of Langley	D	U	115.00	13.09	
34	Lea Hill - East of Auburn	D	U	115.00	13.09	
35	Liquid Air	D	U	115.00	13.09	
36	Lochleven - Bellevue	D	U	115.00	13.09	
37	Long Lake - Port Orchard	D	U	115.00	13.09	
38	Longmire - East of Yelm	D	U	115.00	13.09	
39	Luhr Beach - North of Lacey	D	U	115.00	13.09	
40	Lynden	D	U	115.00	13.09	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)		VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	M Street - Auburn	D	U	115.00	13.09	
2	Manchester	D	U	115.00	13.09	
3	Manhattan - North of Des Moines	D	U	115.00	13.10	
4	Maplewood - Northeast of Renton	D	U	115.00	13.09	
5	Marine View	D	U	115.00	13.09	
6	McAllister Springs	D	U	52.50	14.40	
7	McKenzie - Bellingham	D	U	115.00	13.09	
8	McKinley - Olympia	D	U	115.00	13.09	
9	McWilliams - North of Bremerton	D	U	115.00	13.09	
10	Medina	D	U	115.00	13.09	
11	Mercer Island	D	U	115.00	13.09	
12	Mercerwood - Mercer Island	D	U	115.00	13.09	
13	Merideth	D	U	115.00	13.09	
14	Midlakes - East of Bellevue	D	U	115.00	13.09	
15	Miller Bay - Northeast of Poulsbo	D	U	115.00	13.09	
16	Mirrormont - South of Issaquah	D	U	115.00	13.09	
17	Mottman - West Olympia	D	U	115.00	13.09	
18	Mount Vernon	D	U	115.00	13.09	
19	Murden Cove - Bainbridge Island	D	U	115.00	13.09	
20	Norkirk - Kirkland	D	U	115.00	13.09	
21	Norlum - East Sedro Wooley	D	U	115.00	13.09	
22	Norpac - Kent	D	U	115.00	13.09	
23	North Bellevue	D	U	115.00	13.09	
24	North Bend	D	U	115.00	13.09	
25	North Bothell	D	U	115.00	13.09	
26	North Cle Elum - West of Cle Elum	D	U	115.00	13.09	
27	North Normandy	D	U	115.00	13.09	
28	North Sea-Tac	D	U	12.47	4.16	
29	Northrup - North of Bellevue	D	U	115.00	13.09	
30	Norway Hill - South of Bellevue	D	U	115.00	13.09	
31	Nugents Corner - Northeast of Bellingham	D	U	12.47	12.47	
32	Nugents Corner - Northeast of Bellingham	D	U	34.50	12.47	
33	Nugents Corner - Northeast of Bellingham	D	U	115.00	36.20	
34	Old Town - Bellingham	D	U	115.00	13.09	
35	Olympia	D	U	110.00	55.00	
36	Olympia Brewery - Tumwater	D	U	115.00	13.09	
37	Olympic Arco Pump	D	U	115.00	13.09	
38	Olympic Avon	D	U	115.00	13.09	
39	Olympic Avon	D	U	115.00	13.09	
40	Olympic Bayview	D	U	115.00	13.09	

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1	Olympic Mobil	D	U	115.00	13.09	
2	Olympic Renton	D	U	115.00	13.09	
3	Olympic Vail Pipeline	D	U	115.00	13.09	
4	Orchard - East of Kent	D	U	115.00	13.09	
5	Orillia - North of Kent	D	U	115.00	13.09	
6	Orting	D	U	115.00	13.09	
7	Osceola	D	U	115.00	13.09	
8	Overlake - Medina	D	U	115.00	13.09	
9	Paccar	D	U	115.00	13.09	
10	Padilla Bay Pipeline	D	U	12.47	4.16	
11	Padilla Bay Pipeline	D	U	115.00	13.09	
12	Panther Lake	D	U	117.88	13.09	
13	Patterson - East of Lacey	D	U	115.00	13.09	
14	Peasley Canyon	D	U	115.00	13.09	
15	Peths Corner - La Conner	D	U	115.00	13.09	
16	Phantom Lake - Bellevue	D	U	115.00	13.09	
17	Pickering	D	U	117.88	13.09	
18	Pine Lake - North of Issaquah	D	U	115.00	13.09	
19	Pipe Lake - Kent	D	U	115.00	13.09	
20	Pleasant Glade - North of Lacey	D	U	115.00	13.09	
21	Plum Street - Olympia	D	U	53.81	4.36	
22	Plymouth - Bellingham	D	U	115.00	13.09	
23	Point Roberts	D	U	52.50	14.40	
24	Port Gamble	D	U	115.00	13.09	
25	Port Ludlow	D	U	115.00	13.09	
26	Port Madison - Bainbridge Island	D	U	115.00	13.09	
27	Poulsbo	D	U	115.00	13.09	
28	President Park - Renton	D	U	115.00	13.09	
29	Prine	D	U	115.00	13.09	
30	Quarry	D	U	115.00	13.09	
31	Quarry	D	U	115.00	13.09	
32	Quilcene	D	U	115.00	13.09	
33	Redmond	D	U	115.00	13.09	
34	Redondo - West of Kent	D	U	115.00	13.09	
35	Renton Junction - Renton	D	U	115.00	13.09	
36	Rhodes Lake - North of Orting	D	U	115.00	13.09	
37	Rita Street	D	U	12.47	4.16	
38	Rita Street	D	U	115.00	13.09	
39	Riverbend - Mount Vernon	D	U	115.00	13.09	
40	Rochester	D	U	115.00	13.09	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)		VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Rocky Point - Bremerton	D	U	110.00	14.40	
2	Rocky Point - Bremerton	D	U	110.00	14.00	
3	Rocky Point - Bremerton	D	U	110.00	14.00	
4	Roeder - Bellingham	D	U	12.47	4.16	
5	Roeder - Bellingham	D	U	115.00	13.09	
6	Rolling Hills - Renton	D	U	115.00	13.09	
7	Rose Hill - East of Kirkland	D	U	115.00	13.09	
8	Sahalee - Southeast Redmond	D	U	115.00	13.09	
9	Saint Clair	D	U	110.00	55.00	
10	Scenic	D	U	115.00	13.09	
11	Schuett - South of Sumas	D	U	115.00	13.09	
12	Sea-Tac	D	U	115.00	13.09	
13	Sehome - Bellingham	D	U	12.47	4.16	
14	Sehome - Bellingham	D	U	115.00	13.09	
15	Sequoia - Kent	D	U	115.00	13.09	
16	Shannon	D	U	230.00	36.20	
17	Shaw - South of Puyallup	D	U	115.00	13.09	
18	Sheridan	D	U	110.00	13.09	
19	Sherwood	D	U	115.00	13.09	
20	Shuffleton	D	U	6.60	7.20	
21	Silverdale	D	U	115.00	13.09	
22	Sinclair Inlet - Gorst	D	U	115.00	13.09	
23	Skykomish	D	U	115.00	13.09	
24	Slater - West of Ferdale	D	U	115.00	13.09	
25	Snoqualmie - Northwest of Snoqualmie	D	U	115.00	13.09	
26	Snoqualmie Gen. #1	D	U	115.00	1.90	
27	Snoqualmie Gen. #2	D	U	115.00	6.60	
28	Somerset - South of Bellevue	D	U	115.00	13.09	
29	Soos Creek - Kent	D	U	115.00	13.09	
30	South Bellevue	D	U	115.00	13.09	
31	South Keyport	D	U	115.00	13.09	
32	South Kirkland	D	U	115.00	13.09	
33	South Mercer - Mercer Island	D	U	115.00	13.09	
34	South Sea-Tac	D	U	12.47	4.16	
35	South Whidbey	D	U	115.00	13.20	
36	Southcenter - Tukwila	D	U	115.00	13.09	
37	Southgate	D	U	52.50	7.20	
38	Southwick - Southeast of Lacey	D	U	115.00	13.09	
39	Spanaway	D	U	115.00	13.09	
40	Spiritbrook - Redmond	D	U	115.00	13.09	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Starwood	D U	115.00	13.09	
2	Starwood	D U	120.00	108.00	
3	State Street - Bellingham	D U	12.47	4.16	
4	State Street - Bellingham	D U	115.00	13.09	
5	Stewart - Puyallup	D U	115.00	13.09	
6	Summit Park	D U	53.81	13.09	
7	Sumner	D U	115.00	13.09	
8	Swantown - Oak Harbor	D U	115.00	13.09	
9	Sweptwing - West Angle Lake	D U	115.00	13.09	
10	Tanglewilde - East of Lacey	D U	115.00	13.09	
11	Texaco	D U	12.47	4.16	
12	Texaco East	D U	115.00	13.80	
13	Texaco West	D U	115.00	13.80	
14	Thorp	D U	34.50	12.47	
15	Thorp	D U	33.78	13.09	
16	Thurston - Olympia	D U	12.47	4.16	
17	Thurston - Olympia	D U	53.81	13.09	
18	Thurston - Olympia	D U	53.96	13.00	
19	Tilicum	D U	115.00	13.09	
20	Tolt - Carnation	D U	115.00	13.09	
21	Totem - Kirkland	D U	115.00	13.09	
22	Township	D U	52.50	7.20	
23	Tracyton	D U	115.00	13.09	
24	Valencia	D U	53.81	4.36	
25	Valencia	D U	53.81	4.36	
26	Van Horn - Concrete	D U	34.50	12.47	
27	Van Horn - Concrete	D U	52.50	14.40	
28	Van Horn - Concrete	D U	55.00	14.40	
29	Van Wyck	D U	115.00	13.09	
30	Vashon	D U	115.00	13.09	
31	Victoria Park	D U	115.00	13.09	
32	Viking	D U	115.00	13.09	
33	Vista - North of Ferndale	D U	115.00	13.09	
34	Vitulli	D U	115.00	13.09	
35	Wabash	D U	53.81	13.09	
36	Waterfront	D U	115.00	13.09	
37	Wayne - Bothell	D U	115.00	13.09	
38	West Auburn	D U	115.00	13.09	
39	West Campus - Southwest Federal Way	D U	115.00	13.09	
40	West Issaquah	D U	115.00	13.09	

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1	West Olympia	D U	115.00	13.09	
2	West Olympia	D U	110.00	55.00	
3	Weyerhaeuser	D U	115.00	13.09	
4	White River Gen. Station	D U	115.00	6.60	
5	White River Gen. Station	D U	115.00	6.60	
6	Whitehorn	D U	115.00	13.09	
7	Whitehorn Gen. Station	D U	13.80	0.48	
8	Whitehorn Gen. Station	D U	13.80	4.16	
9	Wilkeson	D U	52.50	14.40	
10	Wilkeson	D U	52.50	14.40	
11	Wilson - West of Burlington	D U	115.00	13.09	
12	Winslow	D U	115.00	13.09	
13	Woburn	D U	115.00	13.09	
14	Woldale - Northeast of Ellensburg	D U	115.00	13.09	
15	Woodland - South of Puyallup	D U	115.00	13.09	
16	Yelm	D U	115.00	13.09	
17	Zenith	D U	115.00	13.09	
18	TOTAL DISTRIBUTION SUBSTATIONS		35596.07	4827.17	
19					
20	SUMMARY-TRANSMISSION CAPACITY				
21	SUMMARY-DISTRIBUTION CAPACITY				
22	TOTAL				
23					
24	A - Attended				
25	U - Unattended				
26	T - Transmission				
27	D - Distribution				
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
325	1		Static Capacitor	1	42	2
50	1					3
13	3					4
210	2					5
75	1					6
55	1					7
300	1					8
80	6					9
1	1					10
5	5		Static Capacitor	1	23	11
650	2		Static Capacitor	1	39	12
325	1					13
325	1					14
325	1					15
25	1		Static Capacitor	2	47	16
325	1					17
40	3					18
6	6					19
325	1					20
325	1					21
533	4					22
650	2					23
83	3					24
3	3		Static Capacitor	1	42	25
5054	52			6	193	26
						27
						28
20	1		Static Capacitor	1	2	29
9	1					30
20	1		Static Capacitor	1	5	31
1	1					32
6	1					33
80	2					34
80	2		Static Capacitor	1	24	35
80	2		Static Capacitor	1	24	36
25	1		Static Capacitor	1	5	37
25	1		Static Capacitor	1	5	38
5	1					39
15	3					40

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70	1					1
3	3					2
3	3					3
105	3					4
20	1		Static Capacitor	1	5	5
10	1					6
20	1		Static Capacitor	1	5	7
6	6		Static Capacitor	1	41	8
50	3					9
48	3		Static Capacitor	1	41	10
20	1		Static Capacitor	1	5	11
50	2		Static Capacitor	2	8	12
20	1		Static Capacitor	1	5	13
20	1		Static Capacitor	1	5	14
20	1		Static Capacitor	1	2	15
20	1		Static Capacitor	1	5	16
20	1		Static Capacitor	1	2	17
25	1		Static Capacitor	1	2	18
25	1		Static Capacitor	1	5	19
25	1					20
25	1					21
50	1					22
10	2		Static Capacitor	2	5	23
25	1		Static Capacitor	1	5	24
20	1		Static Capacitor	1	5	25
20	1					26
19	2		Static Capacitor	1	2	27
20	1					28
20	1		Static Capacitor	1	5	29
20	1					30
25	1		Static Capacitor	1	5	31
25	2					32
20	1		Static Capacitor	1	5	33
25	1		Static Capacitor	1	2	34
40	1		Static Capacitor	1	5	35
20	1		Static Capacitor	1	2	36
20	1		Static Capacitor	1	5	37
20	1					38
15	2		Static Capacitor	1	2	39
20	1		Static Capacitor	1	5	40

SUBSTATIONS (Continued)

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1	1					1
						2
50	1					3
20	1		Static Capacitor	1	5	4
25	1		Static Capacitor	1	5	5
12	1					6
25	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	5	8
20	1					9
20	1		Static Capacitor	1	5	10
25	1		Static Capacitor	1	2	11
4	1					12
9	1					13
20	1		Static Capacitor	1	5	14
20	1		Static Capacitor	1	5	15
25	1		Static Capacitor	1	5	16
25	1					17
1	1					18
3	2					19
1	1					20
20	1		Static Capacitor	1	5	21
25	1					22
25	1		Static Capacitor	2	10	23
25	1		Static Capacitor	1	5	24
25	1		Static Capacitor	1	5	25
50	2		Static Capacitor	1	5	26
4	1					27
25	1		Static Capacitor	1	5	28
20	1		Static Capacitor	1	2	29
25	1					30
2	1					31
3	2					32
40	3					33
25	1		Static Capacitor	1	4	34
150	3					35
68	1					36
20	1		Static Capacitor	1	5	37
50	2		Static Capacitor	2	10	38
20	1		Static Capacitor	1	5	39
25	1		Static Capacitor	1	5	40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
25	1		Static Capacitor	1	5	1
25	1					2
25	1		Static Capacitor	1	3	3
25	1		Static Capacitor	1	5	4
20	1					5
6	1					6
25	1		Static Capacitor	1	2	7
25	1		Static Capacitor	1	5	8
170	2					9
3	2					10
2	2					11
5	2					12
1	1					13
20	1		Static Capacitor	1	2	14
20	1		Static Capacitor	1	5	15
19	2		Static Capacitor	1	5	16
25	1		Static Capacitor	1	2	17
8	1					18
25	1		Static Capacitor	1		19
5	1					20
25	1		Static Capacitor	1	2	21
25	1		Static Capacitor	1	2	22
20	1		Static Capacitor	1	5	23
9	1					24
19	2					25
4	2					26
2	1					27
20	1		Static Capacitor	1	2	28
9	1					29
20	1					30
20	1		Static Capacitor	1	5	31
20	1					32
25	1		Static Capacitor	2	10	33
25	1					34
20	1					35
25	1		Static Capacitor	1	5	36
25	1		Static Capacitor	1	5	37
20	1		Static Capacitor	1	5	38
25	1		Static Capacitor	1	5	39
20	1		Static Capacitor	1	5	40

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1		Static Capacitor	1	2	1
20	1		Static Capacitor	1	2	2
25	1		Static Capacitor	1	5	3
25	1		Static Capacitor	1	5	4
20	1		Static Capacitor	1	5	5
25	1		Static Capacitor	1	5	6
25	1		Static Capacitor	1	5	7
20	1		Static Capacitor	1	5	8
20	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	5	10
20	1		Static Capacitor	1	5	11
20	1					12
30	1					13
1	1		Static Capacitor	1	2	14
25	1		Static Capacitor	1	5	15
25	1		Static Capacitor	1	5	16
50	2		Static Capacitor	2	8	17
20	1		Static Capacitor	1	5	18
25	1		Static Capacitor	1	5	19
25	1		Static Capacitor	1	5	20
40	1					21
4	1					22
20	1		Static Capacitor	1	5	23
20	1		Static Capacitor	1	4	24
25	1		Static Capacitor	1	5	25
25	1		Static Capacitor	1	5	26
20	1		Static Capacitor	1	5	27
25	1		Static Capacitor	1	2	28
25	1					29
18	1		Static Capacitor	1	2	30
25	1		Static Capacitor	1	5	31
25	1		Static Capacitor	1	5	32
20	1					33
25	1		Static Capacitor	1	3	34
20	2					35
25	1		Static Capacitator	1	5	36
25	1		Static Capacitor	2	10	37
25	1		Static Capacitor	1	5	38
20	1		Static Capacitor	1	2	39
40	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1		Static Capacitor	1	5	1
25	1		Static Capacitor	1	2	2
25	1		Static Capacitor	1	5	3
25	1		Static Capacitor	1	5	4
25	1		Static Capacitor	1	5	5
10	3					6
20	1		Static Capacitor	1	5	7
20	1		Static Capacitor	1	5	8
20	1		Static Capacitor	1	5	9
20	1					10
20	1					11
20	1					12
25	1		Static Capacitor	1	5	13
25	1		Static Capacitor	1	5	14
20	1		Static Capacitor	1	5	15
25	1		Static Capacitor	1	5	16
20	1		Static Capacitor	1	5	17
20	1		Static Capacitor	1	2	18
25	1		Static Capacitor	1	5	19
25	1		Static Capacitor	1	5	20
20	1					21
25	1		Static Capacitor	1	5	22
50	2		Static Capacitor	2	10	23
25	1		Static Capacitor	1	5	24
25	1		Static Capacitor	1	5	25
20	1					26
20	1		Static Capacitor	1	5	27
8	1		Static Capacitor	2	7	28
25	1		Static Capacitor	1	5	29
25	1		Static Capacitor	1	5	30
5	1					31
8	1					32
25	1					33
20	1		Static Capacitor	1	5	34
83	3		Static Capacitor	1	42	35
20	1		Static Capacitor	1	3	36
6	1					37
9	1					38
9	1					39
6	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
9	1					1
9	1					2
6	1					3
25	1		Static Capacitor	1	4	4
25	1		Static Capacitor	1	5	5
20	1		Static Capacitor	1	2	6
20	1		Static Capacitor	1	5	7
25	1					8
25	1		Static Capacitor	1	5	9
4	1					10
9	1					11
25	1		Static Capacitor	1	5	12
20	1		Static Capcaitor	1	2	13
25	1		Static Capacitor	1	5	14
20	1		Static Capacitor	1	5	15
25	1		Static Capacitor	1		16
25	1		Static Capacitor	1	5	17
25	1		Static Capacitor	1	5	18
25	1		Static Capacitor	1	3	19
20	1		Static Capacitor	1	5	20
15	2					21
20	1					22
5	3					23
20	1		Static Capacitor	1	4	24
20	1		Static Capacitor	1	5	25
25	1		Static Capacitor	1	5	26
20	1					27
25	1		Static Capacitor	1	5	28
20	1		Static Capacitor	1	5	29
9	1					30
8	1					31
6	1					32
50	2		Static Capacitor	2	10	33
25	1		Static Capacitor	1	5	34
50	2		Static Capacitor	2	10	35
25	1		Static Capacitor	1	5	36
9	1					37
20	1					38
20	1		Static Capacitor	1	5	39
40	2		Static Capacitor	1	5	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
13	1					1
13	1					2
13	1					3
4	1		Static Capacitor	1	5	4
20	1					5
25	1		Static Capacitor	1	5	6
25	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	5	8
83	3		Static Capacitor	1	84	9
4	1					10
20	1					11
50	2					12
4	1					13
9	1					14
25	1		Static Capacitor	1	5	15
25	1					16
25	1		Static Capacitor	1	2	17
40	1		Static Capacitor	1	5	18
25	1		Static Capacitor	1	5	19
1	1					20
20	1		Static Capacitor	1	5	21
20	1		Static Capacitor	1	2	22
9	1					23
20	1		Static Capacitor	1	5	24
25	1					25
15	1					26
38	1					27
25	1		Static Capacitor	1	5	28
25	1		Static Capacitor	1	4	29
25	1		Static Capacitor	1	5	30
20	1		Static Capacitor	1	4	31
25	1		Static Capacitor	1	5	32
20	1					33
8	1		Static Capacitor	2	7	34
30	1					35
25	1		Static Capacitor	1	5	36
6	3					37
20	1		Static Capacitor	1	5	38
20	1		Static Capacitor	1	5	39
25	1		Static Capacitor	1	2	40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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50	2		Static Capacitor	2	10	1
250	1					2
4	1					3
9	1					4
25	1		Static Capacitor	1	2	5
9	1					6
20	1		Static Capacitor	1	2	7
20	1					8
25	1		Static Capacitor	1	3	9
20	1		Static Capacitor	1	5	10
1	1					11
50	2					12
83	2					13
9	1					14
4	1					15
5	1		Static Capacitor	1	5	16
20	1					17
18	1					18
20	1		Static Capacitor	1	5	19
20	1					20
25	1		Static Capacitor	1	5	21
6	3					22
20	1		Static Capacitor	1	2	23
9	1					24
8	1					25
8	1					26
2	1					27
3	2					28
9	1					29
40	2		Static Capacitor	1	5	30
25	1		Static Capacitor	1	5	31
20	1		Static Capacitor	1	5	32
20	1		Static Capacitor	1	5	33
50	2		Static Capacitor	2	10	34
9	1					35
80	4					36
25	1					37
25	1		Static Capacitor	1	4	38
25	1		Static Capacitor	1	2	39
25	1		Static Capacitor	1	5	40

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20	1		Static Capacitor	1	2	1
83	3		Static Capacitor	1	2	2
20	1					3
40	1					4
30	1					5
170	2					6
3	2					7
2	2					8
3	2					9
1	1					10
20	1		Static Capacitor	1	5	11
25	1					12
20	1					13
20	1					14
25	1		Static Capacitor	1	5	15
25	1		Static Capacitor	1	2	16
25	1		Static Capacitor	1	2	17
8374	424			217	1,158	18
						19
4988						20
8316						21
13304						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
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						40

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