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

Form 1 Approved
OMB No. 1902-0021
(Expires 2/29/2009)
Form 1-F Approved
OMB No. 1902-0029
(Expires 2/28/2009)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 2/28/2009)

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Portland General Electric Company	End of 2009/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

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

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent Portland General Electric Company	02 Year/Period of Report End of 2009/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 121 SW Salmon Street, Portland, Oregon 97204	
05 Name of Contact Person Kirk M. Stevens	06 Title of Contact Person Controller & Asst. Treasurer
07 Address of Contact Person *(Street, City, State, Zip Code)* 121 SW Salmon Street, Portland, Oregon 97204	

08 Telephone of Contact Person, *Including Area Code* (503) 464-7121	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name Maria M. Pope	03 Signature Maria M. Pope	04 Date Signed *(Mo, Da, Yr)* 03/30/2010
02 Title SVP, CFO and Treasurer		

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

LIST OF SCHEDULES (Electric Utility)

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

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".

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Substations	426-427	
68	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Four copies will be submitted [ ] No annual report to stockholders is prepared		

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.

Kirk M. Stevens
Controller and Assistant Treasurer
121 SW Salmon Street
Portland, OR 97204

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.

Oregon - Incorporated July 25, 1930.

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.

Property of respondent was not so held during the year.

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

The respondent is engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The respondent also sells electricity and natural gas in the wholesale market to utilities and energy marketers.

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/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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.

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	121 SW Salmon Street Corporation	Company has leased the	100	
2		headquarters complex in		
3		Portland, Oregon and sub-		
4		leases the complex to		
5		Respondent.		
6				
7	World Trade Center Northwest Corporation	Company is the holder of the	100	
8	(A wholly-owned subsidiary of 121 SW Salmon	World Trade Center Franchise		
9	Street Corporation)			
10				
11	Salmon Springs Hospitality Group	Company provides food	100	
12		catering services.		
13				
14	SunWay 1, LLC	Solar power generation	0.01	
15				
16	SunWay 2, LLC	Solar power generation	0.01	
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Schedule Page: 103 Line No.: 14 Column: c

SunWay 1, LLC is a variable interest entity jointly owned by PGE (0.01% interest) and U.S. Bank (99.99% interest). Though PGE has only a 0.01% interest, it is the primary beneficiary of the corporation and exercises direct control over the entity and its operations.

Schedule Page: 103 Line No.: 16 Column: c

SunWay 2, LLC is a variable interest entity jointly owned by PGE (0.01% interest) and U.S. Bank (99.99% interest). Though PGE has only a 0.01% interest, it is the primary beneficiary of the corporation and exercises direct control over the entity and its operations.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chief Executive Officer and President	James J. Piro	550,008
2	Senior Vice President , Finance, Chief Financial	Maria M. Pope	416,508
3	Officer and Treasurer		
4	Vice President, General Counsel and Corporate	J. Jeffrey Dudley	261,528
5	Compliance Officer		
6	Vice President, Nuclear and Power Supply/Generation	Stephen M. Quennoz	256,207
7	Vice President, Administration	Arleen N. Barnett	247,053
8	Senior Vice President, Customer Service and Delivery	Stephen R. Hawke	242,232
9	Vice President, Power Operations and	James F. Lobdell	240,088
10	Resource Strategy		
11	Vice President, Customers & Economic Development	Carol A. Dillin	223,694
12	Vice President, Transmission	Joe A. McArthur	220,008
13	Vice President, Distribution	William O. Nicholson	212,759
14	Vice President, Business and Information Technology	Campbell A. Henderson	207,960
15	and Chief Information Officer		
16	Vice President, Transmission and Distribution Services	O. Bruce Carpenter	177,057
17	Vice President, Public Policy	W. David Robertson	166,073
18	Chief Executive Officer and President	Peggy Y. Fowler	112,500
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Schedule Page: 104 Line No.: 1 Column: a

Effective January 1, 2009, James J. Piro was appointed co-Chief Executive Officer and President of PGE. Effective March 1, 2009, Mr. Piro was appointed Chief Executive Officer and President of PGE.

Schedule Page: 104 Line No.: 1 Column: c

Amounts shown in column (c) consist of salaries only.

Schedule Page: 104 Line No.: 2 Column: a

Appointed to position effective January 1, 2009.

Schedule Page: 104 Line No.: 16 Column: a

Appointed to position effective August 1, 2009.

Schedule Page: 104 Line No.: 17 Column: a

Appointed to position effective August 1, 2009.

Schedule Page: 104 Line No.: 18 Column: a

Retired from position effective March 1, 2009.

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	John W. Ballantine	Chicago, Illinois
2	Private Investor, Retired from First Chicago NBD Corp.	
3	Rodney L. Brown	Seattle, Washington
4	Managing Partner, Cascadia Law Group PLLC	
5	David A. Dietzler	Lake Oswego, Oregon
6	Retired Partner of KPMG LLP	
7	Kirby A. Dyess	Beaverton, Oregon
8	Principal, Austin Capital Management LLC	
9	Peggy Y. Fowler	Portland, Oregon
10	Retired Chief Executive Officer and President of	
11	Portland General Electric Company	
12	Mark B. Ganz	Portland, Oregon
13	President, Chief Executive Officer and Director of	
14	The Regence Group	
15	Corbin A. McNeill, Jr.	Jackson Hole, Wyoming
16	Chair of the Board of Portland General Electric Company,	
17	Retired Chairman and Chief Executive Officer of	
18	Exelon Corp.	
19	Neil J. Nelson	Portland, Oregon
20	Chief Executive Officer and President of Siltronic Corp.	
21	M. Lee Pelton	Salem, Oregon
22	President of Willamette University	
23	James J. Piro	Portland, Oregon
24	Chief Executive Officer and President of	
25	Portland General Electric Company	
26	Robert T. F. Reid	Vancouver, British Columbia, Canada
27	Retired Chair and Corporate Director of British Columbia	
28	Transmission Corporation	
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Schedule Page: 105 Line No.: 7 Column: a

Appointed to PGE's Board of Directors effective June 18, 2009.

Schedule Page: 105 Line No.: 9 Column: a

Retired as Chief Executive Officer effective March 1, 2009.

Schedule Page: 105 Line No.: 23 Column: a

Appointed to PGE's Board of Directors and became co-Chief Executive Officer effective January 1, 2009 and became Chief Executive Officer effective March 1, 2009.

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 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.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

1. None

2. None

3. None

4. None

5. None

6. In January 2009, PGE issued $130 million of First Mortgage Bonds in two series, as authorized by the Public Utility Commission of Oregon in its January 28, 2008 Order No. 08-106 in Docket No. UF 4245. One series is for $67 million, maturing January 15, 2016 at a fixed rate of 6.80%. The other series is for $63 million, maturing January 15, 2014 at a fixed rate of 6.50%.

In March 2009, PGE issued 12,477,500 shares of common stock with net proceeds of approximately $170 million. The shares were issued in an underwritten public offering pursuant to the Company's Registration Statement on Form S-3 (Registration No. 333-143472), filed with the Securities and Exchange Commission on June 1, 2007, and the related prospectus dated June 1, 2007 and prospectus supplement dated March 4, 2009. PGE used the net proceeds from this offering to repay substantially all of its outstanding short-term debt, with the balance used for capital expenditures and general corporate purposes.

On April 16, 2009, PGE issued $300 million of 6.10% First Mortgage Bonds due April 15, 2019, as authorized by the Public Utility Commission of Oregon in its March 16, 2009 Order No. 09-089 in Docket No. UF 4257.

On November 3, 2009, PGE issued $150 million of 5.43% Series First Mortgage Bonds due May 3, 2040, as authorized by the Public Utility Commission of Oregon in its June 22, 2009 Order No. 09-245, and subsequently amended in its October 8, 2009 Order No. 09-405 in Docket No. UF 4259.

On January 15, 2010, PGE issued $70 million of 3.46% Series First Mortgage Bonds due January 15, 2015, as authorized by the Public Utility Commission of Oregon in its June 22, 2009 Order No. 09-245, and subsequently amended in its October 8, 2009 Order No. 09-405, in Docket No. UF 4259.

Pursuant to PGE's application, the Federal Energy Regulatory Commission on January 29, 2010 issued an order in Docket No. ES10-12-000 that authorizes the Company to issue up to $750 million of short-term debt over the two-year period February 7, 2010 through February 6, 2012.

In 2009, PGE issued and repaid short-term debt, of which there was no balance at December 31, 2009.

PGE has the following three unsecured revolving credit facilities that together provide a total of $600 million in available short-term financing: 1) a $370 million facility with a group of banks, of which $10 million and $360 million are scheduled to terminate in July 2012 and July 2013, respectively; 2) a $200 million facility with a group of banks that is scheduled to terminate in December 2012; and, 3) a $30 million facility with a bank that is scheduled to terminate in June 2012. See Page 123, Notes to Financial Statements, Note 8 - Revolving Credit Facilities, for further information.

PGE enters into financial and power purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities. As of December 31, 2009, management believes the likelihood is remote that PGE would be required to perform or otherwise incur any significant losses. The Company has not recorded any liability with respect to these indemnifications.

7. At the 2009 Annual Meeting of Shareholders held on May 13, 2009, PGE shareholders voted to approve an amendment to the Company's Amended and Restated Articles of Incorporation to increase the total number of authorized shares of common stock from 80 million to 160 million shares.

8. As of December 31, 2009, PGE had 2,708 employees, with 889 employees covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. One agreement, which covers 856 employees for the three-year period ending February 28, 2012, was ratified in the third quarter of 2009. The agreement provided a 2.5 percent wage increase in 2009 and also provides for 2 percent increases in both March 2010 and September 2010 and a 3.6 percent increase in 2011.

9. Legal Proceedings:

Citizens' Utility Board of Oregon v. Public Utility Commission of Oregon and Utility Reform Project and Colleen O'Neill v. Public Utility Commission of Oregon, Public Utility Commission of Oregon Docket Nos. DR 10, UE 88, and UM 989, Marion County Oregon Circuit Court, Case No. 94C-10417, the Court of Appeals of the State of Oregon, the Oregon Supreme Court, Case No. SC S45653.

Following the closure of Trojan, PGE, in its 1993 general rate filing, sought OPUC approval to recover through rates future decommissioning costs and full recovery of, and a rate of return on, its Trojan investment. PGE's request was challenged and PGE requested from the OPUC a Declaratory Ruling (Docket DR 10) regarding recovery of the Trojan investment and decommissioning costs. In August 1993, the OPUC issued a Declaratory Ruling in PGE's favor. The Declaratory Ruling was appealed to the Marion County Circuit Court, which in November 1994 upheld the OPUC's Declaratory Ruling. The Citizens' Utility Board (CUB) appealed the decision to the Oregon Court of Appeals.

In PGE's 1995 general rate case (Docket UE 88), the OPUC issued an order (1995 Order) granting PGE full recovery of Trojan decommissioning costs and 87% of its remaining undepreciated investment in the plant. The URP filed an appeal of the 1995 Order to the Marion County Circuit Court, alleging that the OPUC lacked authority to allow PGE to recover Trojan costs through its rates. The CUB also filed an appeal to the Marion County Circuit Court challenging the portion of the 1995 Order that authorized PGE to recover a return on its remaining undepreciated investment in Trojan.

In April 1996, the Marion County Circuit Court issued a decision that contradicted the Court's November 1994 ruling. The 1996 decision found that the OPUC could not authorize PGE to collect a return on its undepreciated investment in Trojan. The 1996 decision was appealed to the Oregon Court of Appeals, where it was consolidated with the earlier appeal of the 1994 decision.

In June 1998, the Oregon Court of Appeals ruled that the OPUC does not have the authority to allow PGE to recover a rate of return on its undepreciated investment in Trojan, but upheld the OPUC's authority to allow PGE's recovery of its undepreciated investment in Trojan and its costs to decommission Trojan (1998 Decision). The court remanded the matter to the OPUC for reconsideration of its 1995 Order in light of the court's decision (1998 Remand).

In August 1998, PGE and the URP each filed a Petition for Review with the Oregon Supreme Court seeking review of that portion of the 1998 Decision relating to PGE's return on its undepreciated investment in Trojan. On November 19, 2002, the Oregon Supreme Court dismissed both Petitions for Review.

In September 2000, PGE, CUB, and the OPUC Staff settled proceedings related to PGE's recovery of its investment in the Trojan plant (Settlement). The URP did not participate in the Settlement and filed a complaint with the OPUC, challenging PGE's application for approval of the accounting and ratemaking elements of the Settlement.

In March 2002, after a full contested case hearing (Docket UM 989), the OPUC issued an order (Settlement Order) denying all of the URP's challenges and approving PGE's application for the accounting and ratemaking elements of the Settlement. The URP appealed the Settlement Order to the Marion County Circuit Court. On November 7, 2003, the Marion County Circuit Court remanded the case to the OPUC to reduce rates or order refunds (2003 Remand). The opinion did not specify the amount or timeframe of any reductions or refunds. PGE and the OPUC each appealed the 2003 Remand to the Oregon Court of Appeals.

On October 10, 2007, the Oregon Court of Appeals issued an opinion that reversed the Settlement Order and remanded the Settlement Order to the OPUC for reconsideration. The Oregon Court of Appeals also vacated the 2003 Remand.

As a result of its reconsideration of the Settlement Order, on September 30, 2008, the OPUC issued an order that requires PGE to refund $33.1 million to customers.

In the order, the OPUC also made the following findings:

- The OPUC has authority to order a utility to issue refunds under certain limited circumstances; and
- PGE's rates that were in effect for the period April 1, 1995 through September 30, 2000 were just and reasonable.

On October 22, 2008, the URP and the Class Action Plaintiffs (described in the Dreyer proceeding below) separately appealed the September 30, 2008 order to the Oregon Court of Appeals.

On December 1, 2008, the OPUC issued an order that suspended the requirements imposed on PGE by the refund methodology outlined in the September 30, 2008 order for 60 days. On January 24, 2009, counsel for the URP and the Class Action Plaintiffs filed a motion with the Oregon Court of Appeals requesting a stay of the refund pending final disposition of their appeal. On February 2, 2009, the OPUC issued Order No. 09-039, which suspended the requirements imposed on PGE by the refund methodology, pending the Court of Appeals decision on the Motion for Stay filed by the URP and Class Action Plaintiffs. Based on the OPUC orders and request for stay, the timing of the refunds to customers is uncertain, but could occur during 2009.

Management cannot predict the ultimate outcome of the above matter. However, it believes that this matter will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on the results of operation and cash flows in a future reporting period.

Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court, Case No. 03C 10639; and Morgan v. Portland General Electric Company, Marion County Circuit Court, Case No. 03C 10640.

On January 17, 2003, two class action suits were filed in Marion County Circuit Court against PGE on behalf of two classes of electric service customers. The Dreyer case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2000 (Current Class) and the Morgan case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2000, but who are no longer customers (Former Class, together with the Current Class, the Class Action Plaintiffs). The suits seek damages of $190 million plus interest for the Current Class and $70 million plus interest for the Former Class, from the inclusion of a return on investment of Trojan in the rates PGE charges its customers.

On April 28, 2004, the plaintiffs filed a Motion for Partial Summary Judgment and on July 30, 2004, PGE also moved for Summary Judgment in its favor on all of the Class Action Plaintiffs' claims. On December 14, 2004, the Judge granted the Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. On March 3, 2005, PGE filed a Petition for a Writ of Mandamus with the Oregon Supreme Court asking the Court to take jurisdiction and command the trial Judge to dismiss the complaints or to show cause why they should not be dismissed. On March 29, 2005, PGE filed a second Petition for an Alternative Writ of Mandamus with the Oregon Supreme Court seeking to overturn the Class Certification.

On August 31, 2006, the Oregon Supreme Court issued a ruling on PGE's Petitions for Alternative Writ of Mandamus abating these class action proceedings until the OPUC responded with respect to the certain issues that had been remanded to the OPUC by the Marion County Circuit Court in the proceeding described above.

On October 5, 2006, the Marion County Circuit Court issued an Order of Abatement in response to the ruling of the Oregon Supreme Court, abating the class actions for one year.

On October 17, 2007, the plaintiffs in the class action suits filed a motion with the Marion County Circuit Court to lift the abatement.

At a status conference on October 15, 2008, the Circuit Court set a schedule for the filing of briefs on the plaintiffs' motion to lift the abatement. Oral argument occurred on January 12, 2009. A decision on the motion to lift the abatement is pending.

Management cannot predict the ultimate outcome of the above matter. However, it believes that this matter will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on the results of operation and cash flows in a future reporting period.

Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western System Power Pool Agreement, Federal Energy Regulatory Commission, Docket Nos. EL01-10-000, et seq., and Ninth Circuit Court of Appeals, Case No. 03-74139 (collectively, Pacific Northwest Refund proceeding).

On July 25, 2001, the FERC called for a preliminary evidentiary hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001. During that period, PGE both sold and purchased electricity in the Pacific Northwest. In September 2001, upon completion of hearings, the appointed administrative law judge issued a recommended order that the claims for refunds be dismissed. In December 2002, the FERC re-opened the case to allow parties to conduct further discovery. In June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. In November 2003 and February 2004, the FERC denied all requests for rehearing of its June 2003 decision. Parties appealed various aspects of these FERC orders to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

On August 24, 2007, the Ninth Circuit issued its decision on appeal, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to (i) address the new market manipulation evidence in detail and account for it in any future orders regarding the award or denial of refunds in the proceedings,

(ii) include sales to CERS in its analysis, and (iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the FERC's ultimate decision to deny refunds. Two requests for rehearing have been filed with the court, with a decision now pending.

On May 17, 2007, the FERC approved a settlement between PGE and certain parties in the California refund case in Docket No. EL00-95, et seq. This resolves the claims as between PGE and the California parties named in the settlement as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 21, 2001. The settlement with the California parties does not resolve potential claims from other market participants relating to transactions in the Pacific Northwest.

Management cannot predict the outcome of the Pacific Northwest Refund proceeding, or whether the FERC will order refunds in the Pacific Northwest, and if so, how such refunds would be calculated. Management believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE's results of operation and cash flows in a future reporting period.

Sierra Club et al. v. Portland General Electric Company, U.S. District Court for the District of Oregon, Case No. CV 08-1136-HA.

On January 15, 2008, plaintiffs sent PGE a sixty-day notice of intent to sue for alleged violations of the federal Clean Air Act (CAA), Oregon's State Implementation Plan (SIP) at PGE's Boardman Coal Plant, and the Plant's CAA Title V permit. On September 30, 2008, the plaintiffs sued PGE for these and additional alleged violations of various environmental related regulations.

The plaintiffs seek injunctive relief that includes permanently enjoining PGE from operating the Boardman Coal Plant except in accordance with the CAA, Oregon's SIP, and the Plant's Title V Permit. In addition, plaintiffs seek civil penalties against PGE including $27,500 per day per alleged violation for violations occurring before March 15, 2004 and $32,500 per day per alleged violation occurring thereafter. The total amount of monetary penalties and damages asserted in the complaint cannot be determined with certainty. However, based solely on the complaint, the Company estimates that the amount is approximately $60 million. The Company believes that it has strong defenses to the plaintiffs' claims and intends to vigorously defend against this lawsuit.

10. None

11. (Reserved)

12. None

13. Changes in Directors and Officers:

Effective March 1, 2009, Peggy Y. Fowler retired as Chief Executive Officer of PGE. Ms Fowler remains a member of PGE's Board of Directors.

Effective January 1, 2009, James J. Piro was appointed co-Chief Executive Officer and President of PGE. Effective March 1, 2009, Mr Piro was appointed Chief Executive Officer and President of PGE.

Effective January 1, 2009, Maria M. Pope was appointed Senior Vice President, Finance, Chief Financial Officer, and

Treasurer of PGE.

Effective June 18, 2009, Kirby A. Dyess was appointed as a director of PGE. Ms. Dyess is a principal in Austin Capital Management LLC in Beaverton, Oregon, a firm that invests in and assists development stage companies.

Effective August 1, 2009, Joe A. McArthur was named Vice President, Transmission; William O. Nicholson was named Vice President, Distribution; Carol A. Dillin was named Vice President, Customers and Economic Development; O. Bruce Carpenter was named Vice President, Transmission and Distribution Services; and William D. Robertson was named Vice President, Public Policy.

14. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	5,594,743,122	5,060,855,525
3	Construction Work in Progress (107)	200-201	406,591,842	281,398,617
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,001,334,964	5,342,254,142
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,684,786,163	2,542,998,566
6	Net Utility Plant (Enter Total of line 4 less 5)		3,316,548,801	2,799,255,576
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		3,316,548,801	2,799,255,576
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		27,051,143	27,023,335
19	(Less) Accum. Prov. for Depr. and Amort. (122)		11,141,302	11,145,794
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	-298,974	-201,554
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		61	200,153
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		98,151,883	92,191,133
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		1,768,677	7,473,748
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		115,531,488	115,541,021
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		12,534,498	9,843,924
36	Special Deposits (132-134)		57,454,600	196,166,301
37	Working Fund (135)		30,802	31,607
38	Temporary Cash Investments (136)		18,000,000	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		141,570,577	140,441,336
41	Other Accounts Receivable (143)		22,067,161	32,010,167
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,199,357	4,375,494
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		349,024	576,847
45	Fuel Stock (151)	227	23,897,315	34,424,362
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	31,433,083	33,259,432
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	11,357	23,250
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	360,000	360,000

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	3,051,673	3,031,841
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		93,677,728	36,859,407
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		95,399,244	96,000,000
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		12,329,416	36,112,211
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		1,768,677	7,473,748
65	Derivative Instrument Assets - Hedges (176)		182,717	2,741,715
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		505,381,161	610,033,158
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		14,510,469	12,645,388
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	654,999,079	814,751,272
73	Prelim. Survey and Investigation Charges (Electric) (183)		4,807,442	1,061,534
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		99,737	-3,170
77	Temporary Facilities (185)		-1,401	0
78	Miscellaneous Deferred Debits (186)	233	10,195,597	6,268,630
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		25,741,617	28,239,657
82	Accumulated Deferred Income Taxes (190)	234	304,550,743	393,934,107
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,014,903,283	1,256,897,418
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,952,364,733	4,781,727,173

Schedule Page: 110 Line No.: 30 Column: d

During the first quarter of 2009, PGE reconsidered the presentation of its derivative instrument assets, which have previously been classified entirely as current. The Company determined that it was preferable to present such assets as either current or long-term based on the expected settlement dates of the underlying contracts for such assets. To conform to the 2009 presentation, reclassifications were made to the December 31, 2008 balance sheet. The long-term portion of derivative instrument assets, in the amount of $7,473,748, was reclassified to a separate caption within Other Property and Investments, with a corresponding reduction from the amount included within Current and Accrued Assets. All amounts related to the above reclassifications and balances were recorded within FERC Account 175, Derivative instrument assets.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Rresubmission	/ /	end of 2009/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	821,983,367	645,024,681
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	15,302,074	15,260,365
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	8,034,721	1,580,183
11	Retained Earnings (215, 215.1, 216)	118-119	720,413,968	701,282,688
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-991,261	-862,441
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-5,532,427	-4,565,452
16	Total Proprietary Capital (lines 2 through 15)		1,543,141,000	1,354,559,658
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,596,500,000	1,158,900,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	149,383,985	149,285,412
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,558,570	1,671,951
24	Total Long-Term Debt (lines 18 through 23)		1,744,325,415	1,306,513,461
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		5,590,393	5,234,912
29	Accumulated Provision for Pensions and Benefits (228.3)		244,007,688	269,910,810
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		37,824,781	16,337,818
32	Long-Term Portion of Derivative Instrument Liabilities		127,111,674	200,415,742
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		63,206,492	57,592,926
35	Total Other Noncurrent Liabilities (lines 26 through 34)		477,741,028	549,492,208
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	195,525,039
38	Accounts Payable (232)		180,924,525	208,096,764
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		-131,899	62,451
41	Customer Deposits (235)		5,535,629	5,858,017
42	Taxes Accrued (236)	262-263	9,246,634	8,829,106
43	Interest Accrued (237)		26,913,692	19,121,286
44	Dividends Declared (238)		19,818,207	15,912,756
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Rresubmission	/ /	end of 2009/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		11,522,387	11,920,566
48	Miscellaneous Current and Accrued Liabilities (242)		15,993,611	70,049,621
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		255,446,757	424,071,492
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		127,111,674	200,415,742
52	Derivative Instrument Liabilities - Hedges (245)		0	1,842,275
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		398,157,869	760,873,631
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		31,959	31,958
57	Accumulated Deferred Investment Tax Credits (255)	266-267	61,995	1,936,711
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	2,595,667	1,521,722
60	Other Regulatory Liabilities (254)	278	106,446,062	124,898,690
61	Unamortized Gain on Reaquired Debt (257)		108,862	140,335
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		404,960,313	335,450,266
64	Accum. Deferred Income Taxes-Other (283)		274,794,563	346,308,533
65	Total Deferred Credits (lines 56 through 64)		788,999,421	810,288,215
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,952,364,733	4,781,727,173

Schedule Page: 112 Line No.: 32 Column: d

During the first quarter of 2009, PGE reconsidered the presentation of its derivative instrument liabilities, which have previously been classified entirely as current. The Company determined that it was preferable to present such liabilities as either current or long-term based on the expected settlement dates of the underlying contracts for such liabilities. To conform to the 2009 presentation, reclassifications were made to the December 31, 2008 balance sheet. The long-term portion of derivative instrument liabilities, in the amount of $200,415,742, was reclassified to a separate caption within Other Noncurrent Liabilities, with a corresponding reduction from the amount included within Current and Accrued Liabilities. All amounts related to the above reclassifications and balances were recorded within FERC Account 244, Derivative instrument liabilities.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STATEMENT OF INCOME

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

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,965,977,746	2,081,478,742		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,345,165,109	1,479,468,115		
5	Maintenance Expenses (402)	320-323	95,125,269	94,008,001		
6	Depreciation Expense (403)	336-337	184,241,239	171,923,174		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	53,948	4,415,797		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	15,718,809	14,293,251		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		4,646,000	4,646,000		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		8,221,953	13,634,112		
13	(Less) Regulatory Credits (407.4)		7,862,322	1,720,492		
14	Taxes Other Than Income Taxes (408.1)	262-263	84,247,655	83,409,551		
15	Income Taxes - Federal (409.1)	262-263	-46,503,818	11,607,911		
16	- Other (409.1)	262-263	-472,910	578,291		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	194,668,799	294,151,399		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	104,229,998	265,958,157		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,456,233	-1,460,620		
20	(Less) Gains from Disp. of Utility Plant (411.6)		67,840	543,769		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		534,666	854,577		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,772,030,326	1,903,307,141		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		193,947,420	178,171,601		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,965,977,746	2,081,478,742					2
						3
1,345,165,109	1,479,468,115					4
95,125,269	94,008,001					5
184,241,239	171,923,174					6
53,948	4,415,797					7
15,718,809	14,293,251					8
						9
4,646,000	4,646,000					10
						11
8,221,953	13,634,112					12
7,862,322	1,720,492					13
84,247,655	83,409,551					14
-46,503,818	11,607,911					15
-472,910	578,291					16
194,668,799	294,151,399					17
104,229,998	265,958,157					18
-1,456,233	-1,460,620					19
67,840	543,769					20
						21
						22
						23
534,666	854,577					24
1,772,030,326	1,903,307,141					25
193,947,420	178,171,601					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		193,947,420	178,171,601		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		342,084	330,685		
33	Revenues From Nonutility Operations (417)		4,536,407	5,311,296		
34	(Less) Expenses of Nonutility Operations (417.1)		4,462,666	4,204,035		
35	Nonoperating Rental Income (418)		1,530,497	1,671,395		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	321,180	13,550		
37	Interest and Dividend Income (419)		535,216	3,182,656		
38	Allowance for Other Funds Used During Construction (419.1)		17,586,528	9,137,747		
39	Miscellaneous Nonoperating Income (421)		7,699,709	-9,970,480		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		27,404,787	4,811,444		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		36,228	38,907		
45	Donations (426.1)		2,192,459	1,836,294		
46	Life Insurance (426.2)		-2,251,603	3,256,489		
47	Penalties (426.3)		-90,923	706,611		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		992,168	724,338		
49	Other Deductions (426.5)		26,457,109	2,123,078		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		27,335,438	8,685,717		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,043,696	1,024,133		
53	Income Taxes-Federal (409.2)	262-263	603,005	58,312		
54	Income Taxes-Other (409.2)	262-263	137,614	-59,461		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	4,913,440	6,007,246		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	11,252,118	10,000,373		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		418,483	516,157		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-4,972,846	-3,486,300		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		5,042,195	-387,973		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		97,557,599	79,772,988		
63	Amort. of Debt Disc. and Expense (428)		2,580,517	2,444,035		
64	Amortization of Loss on Reaquired Debt (428.1)		2,498,040	2,371,763		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		31,474	51,924		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		12,835,105	12,255,236		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		11,816,045	6,183,593		
70	Net Interest Charges (Total of lines 62 thru 69)		103,623,742	90,608,505		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		95,365,873	87,175,123		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		95,365,873	87,175,123		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		697,429,893	670,416,848
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		95,044,693	87,161,573
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	No Par Value		-76,363,413	(60,998,528)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-76,363,413	(60,998,528)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		450,000	850,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		716,561,173	697,429,893
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		3,852,795	3,852,795
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,852,795	3,852,795
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		720,413,968	701,282,688
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-862,441	(25,991)
50	Equity in Earnings for Year (Credit) (Account 418.1)		321,180	13,550
51	(Less) Dividends Received (Debit)		450,000	850,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		-991,261	(862,441)

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Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	95,365,873	87,175,123
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	200,013,996	190,632,222
5	Amortization of Debt Discount	5,047,083	4,763,874
6	Amortization of Unrecovered Plant	4,646,000	4,646,000
7	Net Asset from Price Risk Management	-144,125,217	350,058,715
8	Deferred Income Taxes (Net)	84,100,123	24,200,115
9	Investment Tax Credit Adjustment (Net)	-1,874,716	-1,976,777
10	Net (Increase) Decrease in Receivables	-52,765,961	4,696,317
11	Net (Increase) Decrease in Inventory	12,345,457	-6,894,116
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-13,438,634	-4,697,774
14	Net (Increase) Decrease in Other Regulatory Assets	125,875,020	-520,804,743
15	Net Increase (Decrease) in Other Regulatory Liabilities	-50,660,061	66,555,980
16	(Less) Allowance for Other Funds Used During Construction	17,586,528	9,137,747
17	(Less) Undistributed Earnings from Subsidiary Companies	321,180	13,550
18	Provision for Pension and Other Benefits	7,974,052	181,301,291
19	Other: Margin Deposit (Account 134)	130,947,003	-170,789,955
20	Other Operating	-771,754	-18,392,194
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	384,770,556	181,322,781
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-712,469,168	-367,664,713
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-27,808	-633,375
30	(Less) Allowance for Other Funds Used During Construction	-17,586,528	-9,137,747
31	Other (provide details in footnote):		
32			
33	Other Capital Activities	901,270	-15,654,196
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-694,009,178	-374,814,537
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-31,400	-649,887
40	Contributions and Advances from Assoc. and Subsidiary Companies	450,000	850,000
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Other Investments	-5,713,802	-2,767,048
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	Purchases of Trojan Decommissioning Trust Securities	-35,684,997	-19,146,034
54	Sales of Trojan Decommissioning Trust Securities	36,046,346	23,567,587
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-698,943,031	-372,959,919
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	580,000,000	50,000,000
62	Preferred Stock		
63	Common Stock	175,932,749	
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		195,525,039
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	755,932,749	245,525,039
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-142,301,427	-55,819,381
74	Preferred Stock		
75	Common Stock		
76	Common Stock Issuance Expense	-6,454,539	
77			
78	Net Decrease in Short-Term Debt (c)	-195,525,039	
79	Debt Issue Cost	-4,718,268	-588,440
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-72,071,232	-60,039,380
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	334,862,244	129,077,838
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	20,689,769	-62,559,300
87			
88	Cash and Cash Equivalents at Beginning of Period	9,875,531	72,434,831
89			
90	Cash and Cash Equivalents at End of period	30,565,300	9,875,531

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

Supplemental Disclosures

Supplemental Information to Statement of Cash Flows

Reconciliation between "Cash and Cash Equivalents at Beginning/End of the Year" on Statement of Cash Flows with the related amounts on the Balance Sheet:

	Balance at Beginning of Year	Balance at End of Year
Cash (131)	$ 9,843,924	$ 12,534,498
Working Funds (135)	31,607	30,802
Temporary Cash Investment (136)	-	18,000,000
	$ 9,875,531	$30,565,300

Cash paid during the year:	2008	2009
Interest	$ 79,665,752	$ 86,143,996
AFDC - Borrowed	(6,183,593)	(11,816,045)
	$ 73,482,159	$ 74,327,951
Income taxes	$19,752,530	$1,948,824

NOTE 1: BASIS OF PRESENTATION

Nature of Operations

PGE is a single, vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company also sells electricity and natural gas in the wholesale market to utilities, brokers, and power marketers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. PGE's corporate headquarters is located in Portland, Oregon and its service area is located entirely within Oregon. PGE's service area includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. As of December 31, 2009, PGE served 815,739 retail customers with a service area population of approximately 1.7 million, comprising 43% of the state's population.

As of December 31, 2009, PGE had 2,708 employees, with 890 employees covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers (Local 125). Such agreements cover 856 and 34 employees and expire on February 28, 2012 and August 1, 2011, respectively.

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC) with respect to retail prices, utility services, accounting policies and practices, issuance of securities and certain other matters. Retail prices are based on the Company's cost to serve customers, including an opportunity to earn a reasonable rate of return. The Company is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in matters related to wholesale energy transactions, transmission services, reliability standards, natural gas pipelines, hydroelectric project licensing, accounting policies and practices, short-term debt issuances, and certain other matters.

Financial Statements

These financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than generally accepted accounting principles (GAAP). As a result, the presentation of these financial statements differs from GAAP.

The primary differences include the requirement that PGE report its investments in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries, as required by GAAP. In addition, the FERC requires that certain items on the Balance Sheet be classified differently than that required by GAAP, primarily the classification of current and non-current components of accumulated deferred income taxes, long-term debt, regulatory assets and liabilities, and the classification of Accumulated asset retirement removal costs.

The FERC also requires that certain items on the Statement of Income be classified differently than that required by GAAP. These include the requirement that all gains and losses on non-physical settlements of electricity derivative activities be recorded on a gross basis rather than on a net basis, as required by GAAP (for additional information, see Note 5 - Price Risk Management). In addition, certain items that are considered to be non-operating in nature are recorded in Other Deductions in the FERC Statement of Income but are recorded within Operating Expenses in financial statements prepared in accordance with GAAP. In 2009, such expenses included an approximate $17 million write-off of a portion of a regulatory asset representing deferred excess replacement power costs (plus interest) associated with the forced outage of PGE's Boardman coal plant from late 2005 to early 2006, pursuant to an order from the OPUC. Such expenses in 2009 also included a $6 million charge related to PGE's Selective Water Withdrawal project; for further information, see *Capitalization Policy* in the Property, Plant and Equipment section of Note 2.

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosures of contingent liabilities, as of 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.

PGE considered events through February 24, 2010, for purposes of determining whether any event warranted recognition or disclosure in its annual financial statements as of and for the year ended December 31, 2009.

Reclassifications

During the first quarter of 2009, PGE reconsidered the presentation of its derivative instrument assets and liabilities, which previously had all been classified as current. The Company determined it was preferable to present such assets and liabilities as either current or long-term based on the expected settlement dates of the underlying contracts for such assets and liabilities. To conform to the 2009 presentation, certain reclassifications have been made to the December 31, 2008 balance sheet. These reclassifications consist of the presentation of the long-term portion of derivative instrument assets, in the amount of $7,473,748, under a separate caption within Other Property and Investments, with a corresponding reduction from the amount included within Current and Accrued Assets. Similarly, the long-term portion of derivative instrument liabilities, in the amount of $200,415,742, has been reclassified to a separate caption within Other Noncurrent Liabilities, with a corresponding reduction from the amount included within Current and Accrued Liabilities.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents. Cash equivalents consist of money market funds, of which PGE had $18 million as of December 31, 2009 and none as of December 31, 2008.

Accounts Receivable

Accounts receivable are recorded at invoiced amount and do not bear interest when recorded. A late fee of 1.5% may be assessed on residential account balances after 60 days and on nonresidential balances after 30 days. An account balance is charged-off after efforts have been made to collect such amount, but no sooner than 45 days after the final due date.

Estimated provisions for uncollectible accounts receivable related to retail sales, charged to Administrative and other expense, are recorded in the same period as the related revenues, with an offsetting credit to the allowance for uncollectible accounts. Such estimates are based on management's assessment of the probability of collection of customer accounts, aging of accounts receivable, bad debt write-offs, actual customer billings, and other factors.

Provisions related to wholesale accounts receivable and unsettled positions, charged to Purchased Power, are based on a periodic review and evaluation that includes counterparty non-performance risk and contractual rights of offset when applicable. Actual amounts written off are charged to the allowance for uncollectible accounts.

Price Risk Management

PGE engages in price risk management activities, utilizing financial instruments such as forward, swap, and option contracts for electricity and natural gas, and futures contracts for natural gas. These instruments are measured at fair value and recorded on the balance sheets as assets or liabilities from price risk management activities, unless they qualify for the normal purchases and normal sales exception. Changes in fair value are recognized in the statement of income unless hedge accounting applies, offset by the effects of regulatory accounting.

Certain electricity forward contracts that were entered into in anticipation of serving the Company's regulated retail load meet the requirements for treatment under the normal purchases and normal sales exception. Other activities consist of certain electricity forwards, options and swaps, certain natural gas forwards, options, and swaps, and forward contracts for acquiring Canadian dollars. Such activities are utilized as economic hedges to protect against variability in expected future cash flows due to associated price risk and to minimize net power costs for retail customers.

The OPUC recognizes derivative contracts only at the time of settlement. Contracts that qualify for the normal purchases and normal sales exception are not required to be recorded at fair value. Unrealized gains and losses from contracts that qualify as cash flow hedges are recorded net in other comprehensive income and contracts not designated as cash flow hedges are recorded net in Purchased Power on the statements of income. The timing difference between the recognition of unrealized gains and losses on derivative instruments and their realization and subsequent recovery in rates is recorded as a regulatory asset or regulatory liability to reflect the effects of regulatory accounting.

Electricity sales and purchases that are physically settled are recorded in Revenues and Purchased Power upon settlement, respectively. Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide deposits with certain counterparties. These deposits are based on the contract terms and commodity prices and can vary period to period. These deposits are classified as Margin deposits in the accompanying balance sheets and were $56 million and $189 million as of December 31, 2009 and 2008, respectively.

Inventories

PGE's inventories, recorded at average cost, consist primarily of materials and supplies for use in operations, maintenance and capital activities and fuel for use in generating plants. Fuel inventories include natural gas, oil, and coal. Natural gas inventory is valued at the lower of average cost or market. Oil and coal inventories are valued at average cost as they are recovered at average cost when utilized.

Property, Plant and Equipment

Capitalization Policy

Electric utility plant is capitalized at its original cost. Costs include direct labor, materials and supplies, and contractor costs, as well as indirect costs such as engineering, supervision, employee benefits, and allowance for funds used during construction (AFDC). Plant replacements are capitalized, with minor items charged to expense as incurred. Costs to purchase or develop software applications for internal use only are capitalized and amortized over the estimated useful life of the software. Costs of obtaining a FERC license for the Company’s hydroelectric projects are capitalized and amortized over the related license period.

Costs which are disallowed for recovery in rates are charged to expense at the time such disallowance is probable. Pursuant to a stipulation entered into with the OPUC and other interested parties in January 2010, PGE agreed to forego the recovery of certain capital costs incurred in connection with a delay in the completion of the Selective Water Withdrawal project, and pursue recovery of these costs through insurance and from firms involved in the design, construction and installation of the project. Accordingly, during the fourth quarter of 2009, PGE charged to expense approximately $6 million of costs related to the Selective Water Withdrawal project. Such amount is included in Other Deductions in the statement of income for the year ended December 31, 2009.

PGE records AFDC, which represents the pre-tax cost of borrowed funds used for construction purposes and the rate granted in the latest rate proceeding for equity funds. AFDC is capitalized as part of the cost of plant and credited to the statement of income. The average rate used by PGE was 7% in 2009 and 8% in 2008. AFDC from borrowed funds was $12 million in 2009 and $6 million in 2008 and is reflected in the statements of income as a reduction to interest expense. AFDC from equity funds was $18 million in 2009 and $9 million in 2008 and is reflected as a component of Other income (expense), net.

Costs of periodic major maintenance inspections and overhauls at the Company’s generating plants are charged to operating expense as incurred.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was approximately 3.8% in 2009 and 3.7% in 2008. Estimated asset retirement removal costs included in depreciation expense were $47 million in both 2009 and 2008.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of asset retirement obligations (AROs) and asset retirement removal costs. The studies are conducted every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. On November 18, 2009, PGE filed its most recent depreciation study with the OPUC.

Thermal production plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the forecasted retirement date, which range from 2020 to 2042. Depreciation is provided on the Company's other classes of plant in service over their estimated average service lives, which are as follows:

Production, excluding thermal:	
Hydro	88 years
Wind	27 years
Transmission	48 years
Distribution	30 years
General	13 years

The original cost of depreciable property units, net of any related salvage value, is charged to accumulated depreciation when property is retired and removed from service. Cost of removal expenditures are charged to AROs for assets that meet the definition of a legal obligation and to accumulated depreciation for assets without AROs.

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Amortization expense was $16 million in 2009 and $14 million in 2008. Accumulated amortization was $122 million and $109 million as of December 31, 2009 and 2008, respectively. Future estimated amortization expense as of December 31, 2009 is as follows: $16 million in 2010, $13 million in 2011, $11 million in 2012, $5 million in 2013, and $2 million in 2014.

Marketable Securities

All of PGE's investments in marketable securities, included in the Non-qualified benefit plan trust and Nuclear decommissioning trust on the balance sheets, are classified as trading. Trading securities are stated at fair value based on quoted market prices. Realized and unrealized gains and losses on the Non-qualified benefit plan trust assets are included in Other income (expense), net. Realized and unrealized gains and losses on the Nuclear decommissioning trust fund assets are recorded as regulatory liabilities or assets, respectively, as PGE expects to recover costs for these activities through rates. The cost of securities sold is based on the average cost method.

Regulatory Accounting

Regulatory Assets and Liabilities

As a rate-regulated enterprise, the Company applies regulatory accounting, resulting in regulatory assets or regulatory liabilities. Regulatory assets represent probable future revenue associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are expected to be credited to customers through the ratemaking process. Regulatory accounting 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. Once the regulatory asset or liability is reflected in rates, the respective regulatory asset or liability is amortized to the appropriate line item in the statement of income over the period in which it is included in rates.

Circumstances that could result in the discontinuance of regulatory accounting include (1) increased competition that restricts the Company's ability to establish prices to recover specific costs, and (2) a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. PGE periodically reviews the criteria of regulatory accounting to ensure that its continued application is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management believes that the Company's regulatory assets are probable of future recovery.

See Note 6 for additional information concerning the Company's regulatory assets and liabilities.

Power Cost Adjustment Mechanism

PGE is subject to a power cost adjustment mechanism (PCAM) as approved by the OPUC. Pursuant to the PCAM, the Company can adjust future prices to reflect a portion of the difference between each year's forecasted NVPC included in prices (baseline) and actual NVPC. PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and that included in base prices by application of an asymmetrical deadband within which PGE absorbs cost increases or decreases, with a 90/10 sharing of costs and benefits between customers and the Company, respectively, outside of the deadband. Any customer refund or collection is also subject to a regulated earnings test. A refund will occur only to the extent that it results in PGE's actual return on equity (ROE) for that year being no less than 1% above the Company's latest authorized ROE. A collection will occur only to the extent that it results in PGE's actual ROE for that year being no greater than 1% below the Company's last authorized ROE. PGE's authorized ROE was 10.0% for 2009 and 10.1% for 2008. A final determination of any customer refund or collection is made by the OPUC through an annual public filing and review.

PGE estimates and records amounts related to the PCAM on a quarterly basis during the year. If the projected difference between baseline and actual NVPC for the year exceeds the established deadband, and if forecasted earnings exceed the level required by the regulated earnings test, a regulatory liability is recorded for any future amount payable to retail customers, with offsetting amounts recorded to Purchased Power. If the difference is below the lower end of the deadband, a regulatory asset is recorded for any future amount due from retail customers.

For 2009, the deadband ranged from $15 million below, to $29 million above, the baseline. Although PGE's actual NVPC as determined pursuant to the PCAM for 2009 exceeded the baseline by $22 million, it was within the established deadband and, accordingly, no customer collection was recorded in 2009. A final determination regarding the 2009 PCAM results will be made by the OPUC through a public filing and review in 2010.

For 2008, the deadband ranged from $14 million below, to $28 million above, the baseline. PGE's actual NVPC as determined under the PCAM for 2008 was less than the established baseline by approximately $31 million. No regulatory liability was recorded in 2008 for this amount however, as PGE's earnings did not attain the level required under the PCAM's regulated earnings test.

Asset Retirement Obligations

The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. PGE recognizes those legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Because of the long lead time involved until future decommissioning activities occur, the Company uses present value techniques as quoted market prices and a market-risk premium are not available. The present value of estimated future removal expenditures is capitalized as an ARO on the balance sheets and revised periodically, with actual expenditures charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, which is included in Depreciation and amortization for electric utility plant and Other income (expense), net for non-utility property in the statements of income.

Contingencies

Contingencies are evaluated using the best information available at the time the financial statements are prepared. A material loss contingency is accrued and disclosed when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of possible loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed to the effect that the probable loss cannot be reasonably estimated. A material loss contingency will be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Gain contingencies are recognized when realized and are disclosed when material. Legal costs incurred in connection with loss contingencies are expensed as incurred.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss (AOCL) is comprised of the difference between the pension and other postretirement plans' obligations recognized in net income to date, and the unfunded position as of December 31, 2009 and 2008.

Revenue Recognition

Revenues are recognized as electricity is delivered to customers and include amounts for any services provided. The rates charged to customers are subject to federal (FERC), and state (OPUC) regulation. Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's statements of income. Amounts collected from customers are included in Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $38 million in 2009 and $36 million in 2008.

Retail revenue is billed monthly based on meter readings taken throughout the month. Unbilled revenue represents the revenue earned from the last meter read date through the last day of the month, which has not been billed as of the last day of the month. Unbilled revenue is calculated based on each month's actual net retail system load, the number of days from the last meter read date through the last day of the month, and current retail customer prices.

As a rate-regulated utility, there are situations in which PGE defers the recognition of certain revenues until the period in which the related costs are incurred or approved by the OPUC for amortization. For additional information, see *Regulatory Assets and Liabilities* in this Note 2.

Stock-Based Compensation

The measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, is based on the estimated fair value of the awards. The fair value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service period. PGE attributes the value of stock-based compensation to expense on a straight-line basis.

Income Taxes

Income taxes are accounted for under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amounts and tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in current and future periods that includes the enactment date. Any valuation allowance is established to reduce deferred tax assets to the "more likely than not" amount expected to be realized in future tax returns.

As a rate-regulated enterprise, changes in deferred tax assets and liabilities that are related to certain property are required to be passed on to customers through future rates and are charged or credited directly to a regulatory asset or regulatory liability. These amounts were recognized as net regulatory assets of $91 million and $88 million as of December 31, 2009 and 2008, respectively, and will be included in rates when the temporary differences reverse.

Investment tax credits utilized were deferred and amortized to income over the lives of the related properties, and will be fully amortized by the end of 2011.

Uncertain tax positions represent management's expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are sustained by the taxing authorities, PGE would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company's balance sheet. As of December 31, 2009, PGE had no material uncertain tax positions.

PGE records any interest and penalties related to income tax deficiencies in Interest expense and Other income (expense), net, respectively, in the statements of income.

New Accounting Standards

Adopted Accounting Pronouncements

On September 30, 2009, PGE adopted Statement of Financial Accounting Standards No. (SFAS) 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles - a replacement of FASB Statement No. 162* (SFAS 168). SFAS 168 modifies the U.S. generally accepted accounting principles (GAAP) hierarchy created by SFAS 162 by establishing only two levels of GAAP: authoritative and nonauthoritative. SFAS 168, which was codified within ASC 105, *Generally Accepted Accounting Principles*, establishes the *FASB Accounting Standards Codification* (ASC or Codification) as the single source of authoritative U.S. accounting and reporting standards, except for rules and interpretive releases of the SEC under authority of the federal securities laws, which are sources of authoritative GAAP for SEC registrants. All existing accounting standard documents are superseded and all other accounting literature not included in the Codification is considered nonauthoritative. Accordingly, the Codification is referenced as the sole source of authoritative literature. As the Codification does not change current GAAP, the adoption of SFAS 168 had no material impact on the Company's financial position, results of operation, or cash flows.

On December 31, 2009, PGE adopted FSP FAS 132(R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets* (FSP FAS 132(R)-1), which requires enhanced annual disclosures about plan assets of an employer's defined benefit pension or other postretirement plans. Upon initial application, the provisions of this FSP are not required for earlier periods presented for comparative purposes. The adoption of FSP FAS 132(R)-1, which was codified within ASC 715, *Compensation - Retirement Benefits*, upon the adoption of SFAS 168, did not have a material impact on PGE's financial position, results of operation, or cash flows.

On December 31, 2009, PGE adopted ASU 2009-12, *Fair Value Measurements and Disclosures (Topic 820) - Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2009-12). This Update provides additional guidance related to measuring the fair value of certain alternative investments and permits, in certain situations, a reporting entity to use the net asset value per share as a practical expedient to measure the fair value of these certain alternative investments. The ASU also requires disclosure by major category of investment about the attributes of the investments, such as the nature of any restrictions on the investor's ability to redeem its investments at the measurement date. The adoption of ASU 2009-12, did not have a material impact on PGE's financial position, results of operation, or cash flows.

NOTE 3: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable is net of an allowance for uncollectible accounts of $5 million and $4 million as of December 31, 2009 and 2008, respectively. The following is the activity in the allowance for uncollectible accounts (in millions):

	December 31,	
	2009	2008
Balance as of beginning of year	$ 4	$ 5
Increase (decrease) in provision	9	8
Amounts written off, less recoveries	(8)	(9)
Balance as of end of year	$ 5	$ 4

Trust Accounts

PGE maintains two trust accounts: (1) the non-qualified benefit plan trust, which represents amounts set aside by the Company to fund its obligation under the non-qualified benefit plans, primarily the Supplemental Executive Retirement Plan (SERP), management deferred compensation plans (MDCPs) and other non-qualified plans for certain current and former employees and directors, and (2) the nuclear decommissioning trust, which is restricted to reimbursing PGE for Trojan decommissioning expenditures and represents amounts collected from customers less qualified expenditures plus any realized and unrealized gains and losses on the investments held therein.

The trusts hold investments in cash, cash equivalents, marketable securities, and insurance contracts. The insurance contracts are recorded at cash surrender value, with any changes recorded in earnings. The trusts are comprised of the following investments as of December 31 (in millions):

	Nuclear Decommissioning Trust		Non-Qualified Benefit Plan Trust	
	2009	2008	2009	2008
Cash equivalents	$ 31	$ 27	$ -	$ -
Marketable securities, at fair value:				
Equity securities	-	-	21	23
Debt securities	19	19	4	3
Insurance contracts, at cash surrender value	-	-	22	20
Total	$ 50	$ 46	$ 47	$ 46

NOTE 4: FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of financial instruments, both assets and liabilities recognized and not recognized in PGE's balance sheet, for which it is practicable to estimate fair value is as follows as of December 31, 2009 and 2008:

- The fair value of cash and cash equivalents and short-term debt approximate their carrying amounts due to the short-term nature of these balances;
- Derivative instruments are recorded at fair value and are based on published market indices as adjusted for other market factors such as location pricing differences or internally developed models;
- Certain trust assets, consisting of money market funds and fixed income securities included in the Nuclear decommissioning trust and marketable securities included in the Non-qualified benefit plan trust, are recorded at fair value and are based on quoted market prices; and
- The fair value of long-term debt is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to PGE for debt of similar remaining maturities. As of December 31, 2009, the estimated aggregate fair value of PGE’s long-term debt was $1,818 million, compared to its $1,744 million carrying amount. As of December 31, 2008, the estimated aggregate fair value of PGE’s long-term debt was $1,286 million, compared to its $1,306 million carrying amount.

A fair value hierarchy is used to prioritize the inputs to the valuation techniques used to measure fair value. These three broad levels and application to the Company are discussed below.

Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities and U.S. government treasury securities.

Level 2 - Pricing inputs are other than quoted market prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards and swaps.

Level 3 - Pricing inputs include significant inputs that are generally less observable than objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. At each balance sheet date, the Company performs an analysis of all instruments subject to fair value measurement and includes in Level 3 all of those whose fair value is based on significant unobservable inputs.

The Company's financial assets and liabilities whose fair values were recognized at fair value are as follows by level within the fair value hierarchy (in millions):

	Level 1	Level 2	Level 3	Total
As of December 31, 2009:				
Assets:				
Nuclear decommissioning trust [1]:				
Cash	$ 31	$ -	$ -	$ 31
Debt securities:				
U.S. treasury securities	4	-	-	4
Corporate debt securities	-	8	-	8
Mortgage-backed securities	-	5	-	5
Municipal securities	-	2	-	2
Non-qualified benefit plan trust:				
Equity securities	21	-	-	21
Debt securities - mutual funds	4	-	-	4
Assets from price risk management activities [1]	-	13	-	13
	$ 60	$ 28	$ -	$ 88
Liabilities - Liabilities from price risk management activities [1]	$ -	$ 101	$ 154	$ 255
As of December 31, 2008:				
Assets:				
Nuclear decommissioning trust [1]:				
Cash	$ 27	$ -	$ -	$ 27
Debt securities:				
Mortgage-backed securities	-	7	-	7
Corporate debt securities	-	4	-	4
Municipal securities	-	4	-	4
Other	-	4	-	4
Non-qualified benefit plan trust:				
Equity securities	23	-	-	23
Debt securities - mutual funds	3	-	-	3
Assets from price risk management activities [1]	-	33	6	39
	$ 53	$ 52	$ 6	$ 111
Liabilities - Liabilities from price risk management activities [1]	$ -	$ 297	$ 129	$ 426

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Nuclear decommissioning trust assets reflect the assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) and consist of money market funds and fixed income securities. Non-qualified benefit plan trust reflects the assets held in trust to cover the obligations of PGE's non-qualified benefit plans and consist primarily of marketable securities. These assets also include investments recorded at cash surrender value, which are excluded from the table above.

Assets and liabilities from price risk management activities represent derivative transactions entered into by PGE to manage its exposure to commodity price risk and minimize net power costs for service to the Company's retail customers and may consist of forward, swap, and option contracts for electricity, natural gas, oil, and foreign currency, and futures contracts for natural gas and oil. PGE applies a market based approach to the fair value measurement of its derivative transactions. Inputs into the valuation of derivative activities include forward commodity and foreign exchange pricing, interest rates, volatility and correlation. PGE utilizes the Black-Scholes and Monte Carlo pricing models for commodity option contracts. Forward pricing, which employs the mid-point of the market’s bid-ask spread, is derived using observed transactions in active markets, as well as historical experience as a participant in those markets, and is validated against nonbinding quotes from brokers with whom the Company transacts. Interest rates used to calculate the present value of derivative valuations incorporate PGE’s borrowing ability. The Company also considered the liquidity of delivery points of executed transactions when determining where in the fair value hierarchy a transaction should be classified. PGE considers its creditworthiness and the creditworthiness of its counterparties when determining the appropriateness of a particular transaction’s assigned Level in the fair value hierarchy.

Changes in the fair value of assets and liabilities from price risk management activities classified as Level 3 in the fair value hierarchy were as follows (in millions):

	Years Ended December 31,	
	2009	**2008**
Assets (liabilities) from price risk management activities, net as of beginning of year	$ (123)	$ 1
Net realized and unrealized losses	(47)	(166)
Purchases, issuances, and settlements, net	-	(12)
Net transfers out of Level 3	16	54
Liabilities from price risk management activities, net as of end of year	$ (154)	$ (123)

Net realized and unrealized losses are recorded in Purchased Power in the statements of income, and include $49 million in net losses in 2009 and $120 million in 2008, of Level 3 net realized and unrealized losses that have been fully offset by the effects of regulatory accounting.

NOTE 5: PRICE RISK MANAGEMENT

PGE participates in the wholesale marketplace in order to balance its supply of power, which consists of its own generating resources combined with wholesale market transactions, to meet the needs of its retail customers, manage risk, and administer its existing long-term wholesale contracts. Such activities include power purchases and sales resulting from economic dispatch decisions for its own generation. As a result of this ongoing business activity, PGE is exposed to commodity price risk and foreign currency exchange rate risk, where adverse changes in prices and/or rates may affect the Company's financial position, performance, or cash flow.

PGE utilizes derivative instruments, which may include forward, swap, and option contracts for electricity, natural gas, oil, and foreign currency, and futures contracts for natural gas and oil, in its retail electric utility activities to manage its exposure to commodity price risk and foreign exchange rate risk, mitigate the effects of market fluctuations, and minimize net power costs for service to its retail customers. These derivative instruments are recorded at fair value on the statement of financial position, with changes in fair value recorded in the statement of income. However, as a regulated entity, PGE recognizes a regulatory asset or liability in order to defer the gains and losses from derivative activity until realized, in accordance with ratemaking and cost recovery processes authorized by the OPUC. In effect, this accounting treatment defers the mark-to-market gains and losses on derivative activities until settlement, reducing volatility related to commodity price and foreign currency exchange rate risk. PGE may designate certain derivative instruments as cash flow hedges or may use derivative instruments as economic hedges. PGE does not engage in trading activities for non-retail purposes.

PGE has elected not to net on the balance sheet the positive and negative exposures resulting from derivative instruments entered into with counterparties where a master netting arrangement exists.

As of December 31, 2009, PGE's net volume related to its Price risk management assets and liabilities resulting from its derivative activities, which are expected to deliver or settle at various dates through 2014, was as follows (in millions):

Type	Volume		
Commodity:			
Electricity		12	MWh
Natural gas		96	Decatherms
Foreign exchange	$	5	Canadian

As of December 31, 2009, PGE's Assets and Liabilities from price risk management activities resulting from its derivative activities, offset by regulatory accounting, consist of the following (in millions):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Classification	**Fair Value**	**Balance Sheet Classification**	**Fair Value**
Derivatives not designated as hedging instruments:				
Commodity contracts:				
Electricty	Current assets	$ 6	Current liabilities	$ 57
Natural gas	Current assets	5	Current liabilities	71
Total current derivative activity		11 (1)		128
Commodity contracts:				
Electricity	Noncurrent assets	1	Noncurrent liabilities	24
Natural gas	Noncurrent assets	1	Noncurrent liabilities	103
Total long-term derivative activity		2 (2)		127
Total derivatives not designated as hedging instruments		$ 13		$ 255
Total derivatives		$ 13		$ 255

(1) Included in Other current assets on the balance sheet.
(2) Included in Other noncurrent assets on the balance sheet.

Net realized and unrealized losses on derivative transactions were recognized in the statement of income for the year ended December 31, 2009 as follows (in millions):

Derivatives not designated as hedging instruments	Location of net loss recognized in net income on derivative activities	Net loss recognized in net income on derivative activities *
Commodity contracts:		
Electricity	Purchased power and fuel expense	$ 79
Natural Gas	Purchased power and fuel expense	101

* Unrealized gains and losses and certain realized gains and losses are offset by regulatory accounting. Of the net loss recognized in net income for the year ended December 31, 2009, $98 million has been offset.

Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of December 31, 2009 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2010	2011	2012	2013	Total
Commodity contracts:					
Electricity	$ 51	$ 17	$ 4	$ 1	$ 73
Natural gas	66	39	45	19	169
Net unrealized loss	$ 117	$ 56	$ 49	$ 20	$ 242

The Company's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and Standard and Poor's Ratings Services (S&P). Should Moody's and/or S&P reduce their rating on the Company's unsecured debt to below investment grade, PGE could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, in the form of cash or letters of credit, based on total portfolio positions with each of those counterparties and some other counterparties will have the right to terminate their agreements with the Company.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2009 was $216 million. As of December 31, 2009, the Company had $144 million in posted collateral associated with such liability positions, which consisted entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2009, the cash requirement would have been $207 million.

At December 31, 2009, contracts with four different counterparties represent approximately 70% and 46% of PGE's Price risk management assets and liabilities, respectively. Three counterparties represent 41%, 15%, and 14% of Price risk management assets. Three counterparties (two are also represented in the assets) represent 19%, 14%, and 13% of Price risk management liabilities. No other counterparty represents more than 10% of the Price risk management assets and liabilities.

See Note 4 for additional information concerning the determination of fair value for the Company's Price risk management assets and liabilities.

NOTE 6: REGULATORY ASSETS AND LIABILITIES

The majority of PGE's regulatory assets and liabilities are reflected in customer prices and are amortized over the period in which they are reflected in customer prices. Items not currently reflected in prices are pending before the regulatory body as discussed below.

Regulatory assets and liabilities consist of the following (in millions):

	Weighted Average Remaining Life	December 31, 2009	December 31, 2008
Regulatory assets:			
Price risk management (1)	2 years	$ 243	$ 387
Pension and other postretirement plans (1)	(2)	196	232
Deferred income taxes (1)	(3)	108	106
Deferred broker settlements (1)	1 year	50	-
Boardman power cost deferral	(4)	17	34
Utility rate treatment of income taxes	1 year	7	17
Other	Various	34	39
Total regulatory assets		$ 655	$ 815
Regulatory liabilities:			
Asset retirement obligations (5)	(3)	$ 30	$ 26
Trojan ISFSI pollution control tax credits	(6)	17	17
Power Cost Adjustment Mechanism	1 year	1	19
Other	Various	58	63
Total regulatory liabilities		$ 106	$ 125

(1) Does not include a return on investment.
(2) Recovery expected over the average service life of employees. For additional information see Note 2.
(3) Recovery expected over the estimated lives of the assets.
(4) Recovery will occur in the first quarter of 2010.
(5) Included in rate base for ratemaking purposes.
(6) Timing of refund not yet determined.

As of December 31, 2009, PGE had regulatory assets of $56 million earning a return on investment at the following rates: (1) $34 million at PGE's authorized cost of capital, currently 8.284%; (2) $13 million at the approved rate for deferred accounts under amortization, ranging from 2.05% to 4.27%, depending on the year of approval; and (3) $9 million earning a return by inclusion in rate base.

Price risk management represents the difference between the recognition of unrealized gains and losses on derivative instruments related to price risk management activities and their realization and subsequent recovery in rates. See Note 5.

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in rates when recognized in net periodic benefit cost. See Note 10.

Deferred income taxes represents income tax benefits resulting from property-related timing differences that previously flowed to customers and will be included in rates when the temporary differences reverse. See Note 11.

Deferred broker settlements consist of transactions that have been financially settled by clearing brokers prior to the contract delivery date. These gains and losses are deferred for future rate recovery in the corresponding contract settlement month.

Boardman power cost deferral represents that portion of excess replacement power costs, plus accrued interest, associated with the forced outage of Boardman from November 18, 2005 through February 5, 2006, which was deferred for later ratemaking treatment. In the fourth quarter of 2009, the deferred amount was reduced by $18 million pursuant to a February 12, 2010 OPUC order on the amount to be recovered from customers; such reduction was charged to Other Deductions. Pursuant to the order, collection of the remaining deferred balance will be offset in early 2010 with certain credits currently owed to customers related to accrued savings on decommissioning activities at PGE's closed Trojan Nuclear Plant; such amount is included in Other regulatory liabilities.

Utility rate treatment of income taxes regulatory asset or regulatory liability is established pursuant to Oregon Senate Bill 408 (SB 408), which was enacted in 2005. SB 408 requires regulated investor-owned utilities that provide electric or natural gas service to more closely match income tax amounts forecasted to be collected in revenues with the amount of income taxes paid to governmental entities by the investor-owned utilities or their consolidated group. The law requires a report to be filed annually with the OPUC regarding the amount of taxes paid by the utility and the amount of taxes authorized to be collected in rates. If the difference between these two amounts is greater than $100,000, the utility is required to adjust rates prospectively. In any given reporting year, a regulatory liability is established for future refunds to customers while a regulatory asset is established for future collections from customers, with interest accrued thereon as approved by the OPUC.

Trojan refund liability was established as a result of the OPUC order issued on September 30, 2008 requiring a $33.1 million refund to customers for the settlement of certain Trojan-related matters. By December 31, 2009, PGE had substantially completed the refund to customers, including interest at 9.6% from September 30, 2008 through the date the funds were distributed.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs, which are included in Other noncurrent liabilities in the balance sheet, consist of the following (in millions):

	As of December 31,	
	2009	2008
Trojan decommissioning activities	$ 39	$ 37
Utility plant	14	11
Non-utility property	10	10
Asset retirement obligations	$ 63	$ 58

Trojan decommissioning activities represents the present value of future decommissioning expenditures for the plant which ceased operation in 1993. The remaining decommissioning activities consist of the long-term operation and decommissioning of the ISFSI, an NRC-licensed interim dry storage facility that houses the spent nuclear fuel at the plant site until permanent off-site storage is available. Decommissioning of the ISFSI and final site restoration activities will begin once the spent fuel is shipped to a U.S. Department of Energy (USDOE) facility, which is not expected prior to 2033.

Utility plant represents AROs which have been recognized for the Company's thermal and wind generation sites, distribution and transmission assets where disposal is governed by environmental regulation, as well as the Bull Run hydro project. Decommissioning work has been substantially completed at Bull Run as of December 31, 2009, with the possible demolition of the powerhouse planned for summer 2010 if an alternative use for the facility is not chosen. Environmental monitoring is scheduled to continue through 2012.

The following is a summary of the changes in the Company's AROs (in millions):

	Years Ended December 31, 2009	Years Ended December 31, 2008
Balance as of beginning of year	$ 58	$ 91
Liabilities incurred	-	-
Liabilities settled	(4)	(13)
Accretion expense	4	2
Revisions in estimated cash flows	5	(22)
Balance as of end of year	$ 63	$ 58

Pursuant to regulation, utility plant AROs are included in depreciation expense and in prices charged to customers. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability. Recovery of Trojan decommissioning costs is included in PGE's retail prices, currently at $5 million annually, with an equal amount recorded in Depreciation and amortization expense.

PGE maintains a separate trust account, Nuclear decommissioning trust in the balance sheet, for funds collected from customers through rates to cover the cost of Trojan decommissioning activities. See "Trust Accounts" in Note 3 for additional information on the nuclear decommissioning trust account.

The Oak Grove hydro project and transmission and distribution plant located on public right-of-ways and on certain easements meet the requirements of a legal obligation and will require removal when the plant is no longer in service. An ARO liability is not currently measurable however as management believes that these assets will be used in utility operations for the foreseeable future. Ongoing removable activity as equipment is replaced is charged to accumulated asset retirement removal costs, included in Regulatory liabilities.

NOTE 8: REVOLVING CREDIT FACILITIES

PGE has the following unsecured revolving credit facilities:

- A $370 million unsecured revolving credit facility with a group of banks, of which $10 million is scheduled to terminate in July 2012 and $360 million in July 2013;
- A $200 million credit facility with a group of banks, which is scheduled to terminate in December 2012; and
- A $30 million credit facility with a bank, which is scheduled to terminate in June 2012.

Pursuant to the individual terms of the agreements, all credit facilities may be used for general corporate purposes and as backup for commercial paper borrowings. The $370 million and $30 million credit facilities also permit the issuance of standby letters of credit. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. All credit facilities require annual fees based on PGE’s unsecured credit ratings, and contain customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65% of total capitalization. As of December 31, 2009, PGE was in compliance with this covenant with a 53.1% debt ratio.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the credit facilities.

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt up to $750 million through February 6, 2012. The authorization provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

As of December 31, 2009, PGE had no borrowings or commercial paper outstanding under the credit facilities and had $163 million in letters of credit outstanding. As of December 31, 2009, the aggregate unused available credit under the credit facilities is $437 million.

Short-term borrowings under these credit facilities and related interest rates were as follows (dollars in millions):

	Years Ended December 31, 2009	Years Ended December 31, 2008
Average daily amount of short-term debt outstanding	$ 28	$ 33
Weighted daily average interest rate (1)	1.3%	3.8%
Maximum amount outstanding during the year	$ 205	$ 199

(1) Excludes the effect of commitment fees, facility fees and other financing fees.

NOTE 9: LONG-TERM DEBT

Long-term debt consists of the following (in millions):

	As of December 31, 2009	As of December 31, 2008
First Mortgage Bonds, rates range from 4.45% to 9.31%, with a weighted average rate of 6.0% in 2009 and 2008, due at various dates through 2040	$ 1,550	$ 970
Pollution Control Revenue Bonds:		
Port of Morrow, Oregon, 5.2% rate to 2009 and variable thereafter, due 2033	23	23
City of Forsyth, Montana, 5.2% to 5.45% rate to 2009 and variable thereafter, due 2033	119	119
Port of St. Helens, Oregon, 4.8% to 5.25% rate, due 2010 to 2014	47	47
Total Pollution Control Revenue Bonds	189	189
7.875% unsecured notes, due March 10, 2010	149	149
Purchase of pollution control revenue bonds	(142)	-
Unamortized debt discount	(2)	(2)
Total long-term debt	$ 1,744	$ 1,306

First Mortgage Bonds - The Indenture securing PGE's First Mortgage Bonds constitutes a direct first mortgage lien on substantially all utility property, other than expressly excepted property. During 2009, PGE issued a total of $580 million of first mortgage bonds as follows:

- On January 15th, $67 million of 6.8% Series due January 15, 2016, with interest payable semi-annually on January 15th and July 15th;
- On January 15th, $63 million of 6.5% Series due January 15, 2014, with interest payable semi-annually on January 15th and July 15th;
- On April 16th, $300 million of 6.1% Series due April 15, 2019, with interest payable semi-annually on April 15th and October 15th; and
- On November 30th, $150 million of 5.43% Series due May 3, 2040, with interest payable semi-annually on May 15th and November 15th.

On January 15, 2010, PGE issued $70 million of 3.46% Series First Mortgage Bonds that mature January 15, 2015, with interest payable semi-annually on January 15th and July 15th.

Pollution Control Revenue Bonds - On May 1, 2009, PGE repurchased $142 million of Pollution Control Revenue Bonds (Bonds), consisting of $23 million issued through the Port of Morrow, Oregon, and $119 million issued through the City of Forsyth, Montana. PGE has the option to remarket the Bonds and can choose a new interest rate period that would be daily, weekly, or a fixed term. The new interest rate would be based on market conditions at the time of remarketing and could be backed by first mortgage bonds or a bank letter of credit depending on market conditions.

As of December 31, 2009, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2010	$ 186
2011	-
2012	100
2013	100
2014	73
Thereafter	1,285
	$ 1,744

Interest is payable semi-annually on all long-term debt instruments.

NOTE 10: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

Defined Benefit Pension Plan - PGE sponsors a non-contributory defined benefit pension plan, of which substantially all participants are current or former PGE employees. The assets of the pension plan are held in a trust and are comprised in investment vehicles such as: common stocks, mutual funds, private equity funds, fixed income securities, common and collective trust funds, partnerships/joint ventures, corporate debt securities, and other investments; all of which are recorded at fair value. Pension plan calculations include several assumptions which are reviewed annually and are updated as appropriate. The measurement date for the pension plan is December 31.

PGE made no contributions to the pension plan in 2009 and 2008 and does not expect to make any contribution in 2010. As a result of the underfunded status of the pension plan as of January 1, 2010, the Company is expected to make an estimated contribution of $19 million in 2011.

Effective January 31, 2009, the pension plan was closed to new non-bargaining employees, with no changes in benefits to current participants of the pension plan. For non-bargaining employees hired on or after February 1, 2009, the pension plan has been replaced with a new contribution to the defined contribution plan. For additional information, see description of the Company's 401(k) plan included in this Note. Effective January 1, 1999, the pension plan was closed to new bargaining employees.

Other Postretirement Benefits - PGE has non-contributory postretirement health and life insurance plans (collectively "Other Postretirement Benefits" in the following tables). Employees are covered under a Defined Dollar Medical Benefit Plan which limits PGE's obligation by establishing a maximum benefit per employee with employees paying the additional cost. Contributions made to a voluntary employees' beneficiary association trust are used to fund these plans. The assets of other postretirement plans are comprised of investments in: money market funds, common stocks, common and collective trust funds, partnerships/joint ventures, and registered investment companies, all of which are recorded at fair value. Costs of these plans, based upon an actuarial study, are included in rates charged to customers. Postretirement benefit plan calculations include several assumptions which are reviewed annually with PGE's consulting actuaries and trust investment consultants and updated as appropriate.

PGE has Health Reimbursement Accounts (HRAs) for its employees. Contributions are made to trust accounts to provide for claims by retirees for qualified medical costs. For active bargaining employees, the participants' accounts are credited with 58% of the value of the employee's accumulated sick time as of April 30, 2004, plus 100% of their earned time off accumulated at the time of retirement. Between July 1, 2007 and June 30, 2008, the Company made additional contributions to the trust of $0.25 per compensable hour for each bargaining unit participant, increasing to $0.50 per compensable hour from July 1, 2008 through March 3, 2009. The compensable hour contribution as of March 4, 2009 has been redirected to the participants' 401(k) plan. For active non-bargaining employees, the Company grants a fixed dollar amount that will become available for qualified medical expenses upon their retirement.

Minimal contributions were made to the postretirement and non-bargaining HRA plans in 2009 and 2008. Contributions totaling $1 million were made to the bargaining unit HRA in 2009 and 2008. No contributions are currently expected to be made to the other postretirement plans in 2010. The measurement date for the postretirement plans is December 31.

Non-Qualified Benefit Plans - The Non-Qualified Benefit Plans (NQBP) in the following tables consist primarily of obligations for a SERP, which was closed to new participants in 1997. Investments in a non-qualified benefit plan trust, consisting of trust-owned life insurance policies and marketable securities, provide funding for the future requirements of these plans. These trust assets are included in the accompanying tables for informational purposes only and are not considered segregated and restricted under current accounting standards. The investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and recorded at fair value. The measurement date for the non-qualified benefit plans is December 31.

Other Compensation Plans - In addition to the non-qualified benefit plans discussed above, PGE provides certain employees with benefits under unfunded MDCPs, whereby participants may defer a portion of their compensation, as well as other non-qualified plans for certain employees and directors. PGE holds investments in a non-qualified benefit plan trust which are intended to be the primary source for funding these plans.

The following table provides information on the trust assets and plan liabilities included in PGE's balance sheets as of December 31, 2009 and 2008 (in millions):

	2009			2008		
	NQBP	**MDCP**	**Total**	**NQBP**	**MDCP**	**Total**
Non-qualified benefit plan trust	$ 20	$ 27	$ 47	$ 18	$ 28	$ 46
Non-qualified benefit plan liabilities (1)	25	71	96	23	68	91

(1) For the NQBP, excludes the current portion of $2 million in 2009 and 2008, which is classified in Other current liabilities in the balance sheets.

Investment Policy and Asset Allocation - The Board of Directors of PGE appoints an Investment Committee, which is comprised of officers of the Company. In addition, the Board also establishes the Company's asset allocation of risk. The Investment Committee is then responsible for implementation and oversight of the asset allocation. The Company's investment policy for its pension and other postretirement plans is to balance risk and return through a diversified portfolio of equity securities, fixed income securities and other alternative investments. The commitments to each class are controlled by an asset deployment and cash management strategy that takes profits from asset classes whose allocations have shifted above their target ranges to fund benefit payments and investments in asset classes whose allocations have shifted below their target ranges.

The asset allocations for the plans, and the target allocation, are as follows:

	December 31, 2009	December 31, 2008	Target
Defined Benefit Pension Plan:			
Equity securities	67 %	68 %	67 %
Debt securities	33	32	33
	100 %	100 %	100 %
Other Postretirement Benefit Plans:			
Equity securities	50 %	60 %	60 %
Debt securities	50	40	40
	100 %	100 %	100 %
Non-Qualified Benefits Plans:			
Debt securities	8 %	7 %	16 %
Equity securities	46	51	38
Insurance contracts	46	42	46
	100 %	100 %	100 %

The Company's overall investment strategy is to meet the goals and objectives of the individual plans through a wide diversification of asset types, fund strategies, and fund managers. Equity securities primarily include investments across the capitalization ranges and style biases, both domestically and internationally. Fixed income securities include, but are not limited to, corporate bonds of companies from diversified industries, mortgage-backed securities, and U.S. Treasuries. Other types of investments include investments in hedge funds and private equity funds that follow several different strategies.

The fair values of the Company's pension plan assets and other postretirement benefit plan assets as of December 31, 2009 by asset category are as follows (in millions):

	Level 1	Level 2	Level 3	Total
Defined Benefit Pension Plan assets:				
Equity securities:				
U.S. small cap core	$ 11	$ -	$ -	$ 11
U.S. small cap value	12	-	-	12
U.S. micro cap	12	-	-	12
U.S. large cap growth	-	24	-	24
U.S. large cap value	-	23	-	23
Large cap long/short	-	47	-	47
International large cap growth	-	46	-	46
Fixed income securities:				
U.S. core plus	-	34	-	34
U.S. long government/credit	-	32	-	32
Short duration	-	2	-	2
Mutual funds (1)	123	-	-	123
Private equity funds (2)	-	-	17	17
U.S. large cap futures and U.S. hedge funds (3)	-	-	23	23
	$ 158	$ 208	$ 40	$ 406
Other Postretirement Benefit Plans assets:				
Equity securities:				
U.S. small cap core	$ 1	$ -	$ -	$ 1
U.S. large cap growth	-	2	-	2
U.S. large cap value	-	1	-	1
International large cap growth	-	1	-	1
Fixed income securities:				
Short term investment fund	-	7	-	7
Mutual funds	7	-	-	7
	$ 8	$ 11	$ -	$ 19

(1) Mutual funds: a combination of small capitalization growth equity and medium and long duration fixed income funds which can invest across all of the major fixed income sectors. These mutual funds are actively managed.

(2) Private equity: a combination of primary and secondary fund-of-funds which hold ownership positions in privately held companies across the major domestic and international private equity sectors, including but not limited to, venture capital, buyout and special situations.

(3) Portable alpha: an investment mandate comprised of long position in S&P 500 futures contracts and a hedge fund-of-funds comprised of diversified group, by sector and market capitalization of long only, short only and/or both long/short equity hedge funds.

Changes in the fair value of assets held by the pension plan classified as Level 3 in the fair value hierarchy presented in the table above were as follows for the year ended December 31, 2009 (in millions):

	Private equity	U.S. large cap and U.S. hedge funds	Total Level 3
Balance as of December 31, 2008	$ 16	$ 18	$ 34
Purchases and sales	1	1	2
Unrealized gain on assets	-	4	4
Balance as of December 31, 2009	$ 17	$ 23	$ 40

Trust assets and obligations related to the other compensation plans are not included in the following tables.

The following tables provide certain information with respect to the Company's defined benefit pension plan, other postretirement benefits, and non-qualified benefit plans as of and for the years ended December 31, 2009 and 2008 (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2009	2008	2009	2008	2009	2008
Benefit obligation:						
As of January 1	$ 467	$ 475	$ 73	$ 68	$ 25	$ 24
Service cost	11	12	2	2	-	-
Interest cost	31	30	4	4	2	2
Plan amendments	1	-	-	-	-	-
Participants' contributions	-	-	2	1	-	-
Actuarial (gain) loss	5	(24)	2	3	2	1
Benefit payments	(24)	(26)	(6)	(5)	(2)	(2)
As of December 31	$ 491	$ 467	$ 77	$ 73	$ 27	$ 25
Fair value of plan assets:						
As of January 1	$ 347	$ 518	$ 19	$ 27	$ 18	$ 25
Actual return on plan assets	83	(145)	3	(6)	4	(5)
Company contributions	-	-	1	2	-	-
Participants' contributions	-	-	2	1	-	-
Benefit payments	(24)	(26)	(6)	(5)	(2)	(2)
As of December 31	$ 406	$ 347	$ 19	$ 19	$ 20	$ 18
Unfunded position as of December 31	$ (85)	$ (120)	$ (58)	$ (54)	$ (7)	$ (7)

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2009	2008	2009	2008	2009	2008
Accumulated benefit plan obligation as of December 31	$ 446	$ 420	N/A	N/A	$ 26	$ 25
Classification in balance sheet:						
Noncurrent asset	$ -	$ -	$ -	$ -	$ 20	$ 18
Noncurrent liability	(85)	(120)	(58)	(54)	(27)	(25)
Net liability	$ (85)	$ (120)	$ (58)	$ (54)	$ (7)	$ (7)
Amounts included in comprehensive income:						
Net actuarial (gain) loss	$ (35)	$ 166	$ -	$ 12	$ 2	$ 1
Prior service cost	1	-	-	-	-	-
Amortization of net actuarial gain (loss)	-	-	(1)	-	-	1
Amortization of prior service cost	(1)	(1)	(1)	(1)	-	-
Amortization of transition obligation	-	-	-	(1)	-	-
	$ (35)	$ 165	$ (2)	$ 10	$ 2	$ 2
Amounts included in AOCL (1):						
Net actuarial loss	$ 167	$ 202	$ 20	$ 21	$ 9	$ 8
Prior service cost	3	2	6	7	-	-
	$ 170	$ 204	$ 26	$ 28	$ 9	$ 8
Assumptions used:						
Average discount rate used to calculate benefit obligation	5.90%	6.90%	4.66% - 5.92%	5.77% - 6.09%	5.90%	6.90%
Weighted average rate of increase in future compensation levels	3.79%	4.42%	5.07%	5.07%	N/A	N/A
Long-term rate of return on plan assets	8.50%	9.00%	6.88%	7.67%	N/A	N/A

(1) Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to Regulatory assets due to the future recoverability from retail customers. Accordingly, as of the balance sheet date, such amounts are included in Regulatory assets.

Net periodic benefit cost consists of the following for the years ended December 31 (in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2009	2008	2009	2008	2009	2008
Service cost	$ 11	$ 12	$ 2	$ 2	$ -	$ -
Interest cost on benefit obligation	31	30	4	4	2	2
Expected return on plan assets	(43)	(45)	(1)	(2)	-	-
Amortization of transition obligation	-	-	-	1	-	-
Amortization of prior service cost	1	1	1	1	-	-
Amortization of net actuarial loss	-	-	1	-	-	-
Net periodic benefit cost	$ -	$ (2)	$ 7	$ 6	$ 2	$ 2

PGE estimates that $7 million will be amortized from AOCL into net periodic benefit cost in 2010, consisting of a net actuarial loss of $3 million for pension benefits, $1 million for non-qualified benefits and $1 million for other postretirement benefits, and prior service cost of $1 million for pension benefits and $1 million for other postretirement benefits.

The following table summarizes the benefits expected to be paid to participants in each of the next five years and in the aggregate for the five years thereafter (in millions):

	Payments Due					
	2010	2011	2012	2013	2014	2015 - 2019
Defined benefit pension plan	$ 27	$ 29	$ 31	$ 33	$ 34	$ 187
Other postretirement benefits	6	6	6	6	6	28
Non-qualified benefit plans	2	2	3	2	3	12
Total	$ 35	$ 37	$ 40	$ 41	$ 43	$ 227

All of the plans develop expected long-term rates of return for the major asset classes using long-term historical returns, with adjustments based on current levels and forecasts of inflation, interest rates, and economic growth. Also included are incremental rates of return provided by investment managers whose returns are expected to be greater than the markets in which they invest.

For measurement purposes, a 7.5% annual rate of increase in the per capita cost of covered health care benefits is assumed for 2010. The rate is assumed to decrease to 5% by 2015 and remain at that level thereafter. Assumed health care cost trend rates can affect amounts reported for the health care plans. A one-percentage point increase or decrease in assumed health care cost trend rates would not have a material impact on total service or interest cost, but would increase the postretirement benefit obligation by $1 million and decrease it by $1 million, respectively.

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan, which covers substantially all employees. For eligible employees hired prior to February 1, 2009, employee contributions to the 401(k) Plan, made on a "pre-tax" basis, are matched by the Company up to 6% of base pay. For contributions made by eligible employees hired after January 31, 2009, and/or who are not covered by a defined benefit pension plan, the Company will match up to 5% of the participating employee's base salary. In addition, PGE makes an additional 5% contribution for these employees regardless of whether or not the employees make a contribution.

For bargaining employees, contributions are based upon provisions of the International Brotherhood of Electrical Workers Local 125 agreement that became effective on March 1, 2009. The following additions were made to the 401(k) plan for active bargaining employees:

- Effective March 4, 2009, the $0.50 per compensable hour contribution, previously deposited into the employee's HRA, is re-directed to the participants' 401(k) plan. This contribution to the participants' 401(k) plan will increase to $1.00 per compensable hour effective November 1, 2011.
- Effective March 3, 2010, employees will receive an additional 1% Company contribution based on the employee's base salary. This is a Company contribution regardless of whether or not the employee makes a contribution.

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. During each of the years ended December 31, 2009 and 2008, PGE made contributions of approximately $14 million.

NOTE 11: INCOME TAXES

Income tax expense (benefit) consists of the following (in millions):

	Years Ended December 31, 2009	Years Ended December 31, 2008
Current:		
Federal	$ (46)	$ 11
State and local	-	1
	(46)	12
Deferred:		
Federal	71	20
State and local	13	4
	84	24
Investment tax credit adjustments	(2)	(2)
Income tax expense	$ 36	$ 34

The significant differences between the U.S. federal statutory rate and PGE's effective tax rate for financial reporting purposes are as follows:

	Years Ended December 31,	
	2009	2008
Federal statutory tax rate	35.0 %	35.0 %
Federal tax credits	(8.0)	(6.7)
Investment tax credits	(1.4)	(1.6)
State and local taxes, net of federal tax benefit	3.7	1.4
Flow through depreciation	(1.6)	(0.8)
Other	(0.3)	1.1
Effective tax rate	27.4 %	28.4 %

Deferred income tax assets and liabilities consist of the following (in millions):

	As of December 31,	
	2009	2008
Deferred income tax assets:		
Regulatory liabilities	$ 78	$ 89
Price risk management	98	164
Employee benefits	76	97
Depreciation and amortization	37	30
Other	16	14
Total deferred income tax assets	305	394
Deferred income tax liabilities:		
Depreciation and amortization	436	367
Price risk management	117	172
Employee benefits	48	62
Regulatory assets	48	52
Other	31	29
Total deferred income tax liabilities	680	682
Deferred income tax liability, net	$ (375)	$ (288)

(1) Included in Other current assets in the balance sheet as of December 31, 2008.
(2) Included in Other current liabilities in the balance sheet as of December 31, 2009.

As of December 31, 2009, PGE had net operating loss carryforwards for state income tax purposes of $0.4 million, which are available to reduce future state taxable income through 2024. In addition, PGE has Oregon tax credit carryforwards of approximately $12 million, which are available to reduce future state income taxes between 2010 and 2017.

PGE generated approximately $13 million of Oregon tax credits that, due to taxable income limitations, were not utilized by Enron (former parent company of PGE) prior to the separation of the two companies on April 3, 2006. Prior to 2006, pursuant to a tax sharing agreement, PGE utilized these tax credits to reduce its tax payment obligations to Enron. In 2008, PGE made an assessment that it is remote that Enron will be able to utilize these tax credits. Therefore, the realization of such tax credits by PGE was reflected as an adjustment to equity, net of the related federal tax effect, during the year ended December 31, 2008.

PGE files income tax returns in the U.S. federal jurisdiction, the states of Oregon and Montana, and certain local jurisdictions. Open tax years are 2006 and subsequent years for federal, state, and local tax purposes. The Internal Revenue Service informed PGE that examination of PGE's income tax returns for 2007 and 2008 will commence in the first quarter of 2010. The Company is not currently under examination by state or local tax authorities.

NOTE 12: EMPLOYEE STOCK PURCHASE PLAN

In May 2007, PGE shareholders approved the Portland General Electric Company 2007 Employee Stock Purchase Plan (ESPP), under which a total of 625,000 shares may be issued. The ESPP permits all eligible Company employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 worth of stock (based on fair market value on the purchase date) or 1,500 shares, whichever is less. There are two six-month offering periods each year, January 1 - June 30 and July 1 - December 31, during which eligible employees may purchase shares of PGE common stock at a price equal to 95% of the fair market value of the stock on the purchase date, the last day of the offering period. During the years ended December 31, 2009 and 2008, the Company issued 29,648 shares and 25,586 shares, respectively, under the ESPP, with proceeds totaling approximately $0.6 million and $0.5 million, respectively.

NOTE 13: STOCK-BASED COMPENSATION EXPENSE

Pursuant to the Portland General Electric Company 2006 Stock Incentive Plan (the Plan), the Company may grant a variety of equity-based awards, including restricted stock units with time-based vesting conditions (Restricted Stock Units) and performance-based vesting conditions (Performance Stock Units) to non-employee directors, officers and certain key employees. Service requirements generally must be met for stock units to vest. For each grant, the number of Stock Units is determined by dividing the specified award amount for each grantee by the closing stock price on the date of grant. A total of 4,687,500 shares of common stock were registered for future issuance under the Plan, of which 4,095,570 shares remain available for future issuance as of December 31, 2009.

Restricted Stock Units vest in either equal installments over a one-year period on the last day of each calendar quarter, over a three-year period on each anniversary of the grant date, or at the end of a three-year period following the grant date.

Performance Stock Units vest if performance goals are met at the end of a three-year performance period. Vesting of Performance Stock Units will be calculated by multiplying the number of units granted by a performance percentage determined by the Compensation and Human Resources Committee of PGE’s Board of Directors. The performance percentage will be calculated based on the extent to which the performance goals are met. In accordance with the Plan, however, in determining results relative to these goals, the committee may disregard or offset the effect of extraordinary, unusual or non-recurring items. Based on the attainment of the performance goals, the awards can range from zero to 150% of the grant.

Outstanding Restricted and Performance Stock Units provide for the payment of one Dividend Equivalent Right (DER) for each stock unit, which is an amount equal to dividends paid to shareholders on a share of PGE’s common stock. The DERs vest on the same schedule as the stock units and are settled in cash (for grants to non-employee directors) or shares of PGE common stock valued either at the closing stock price on the vesting date (for Performance Stock Unit grants) or dividend payment date (for all other grants). The cash from the settlement of the DERs for non-employee directors may be deferred under the terms of the Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan.

Restricted and Performance Stock Unit activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2007	253,251	$ 26.28
Granted	133,199	22.66
Forfeited	(3,392)	25.02
Vested	(22,676)	24.87
Outstanding as of December 31, 2008	360,382	25.04
Granted	243,574	14.95
Forfeited	(4,847)	24.85
Vested	(176,846)	23.60
Outstanding as of December 31, 2009	422,263	19.82

The vesting of Restricted and Performance Stock Units presented in the table above differ from the number of shares issued for the vesting of restricted stock units on the statements of shareholders' equity because of the payment of income taxes on behalf of the employees, in the form of shares, and the vesting of DERs, which totaled 48,671 shares in 2009 and 2,792 shares in 2008.

The weighted average fair value is measured based on the closing price of PGE common stock on the date of grant. For the years ended December 31, 2009 and 2008, PGE recorded $1.4 million and $4 million, respectively, of stock-based compensation expense, which is included in Administrative and other expense in the statements of income. The recorded $1.4 million expense for 2009 is different than the amount reported in the statement of shareholders' equity for Stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The net impact to equity from the income tax payments, partially offset by the issuance of DERs, resulted in a $1.0 million charge to equity not reported in Administrative and other expenses in the statement of income.

As of December 31, 2009, unrecognized stock-based compensation expense was $1.9 million, of which $1.0 million and $0.9 million is expected to be expensed in 2010 and 2011, respectively. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the vesting of 82.3% and 0% of awarded Performance Stock Units for 2009 and 2008, respectively, with an estimated 5% forfeiture rate. No stock-based compensation costs have been capitalized and the plan had no material impact on cash flow for the years ended December 31, 2009 or 2008.

NOTE 14: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2009, PGE's future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2010	2011	2012	2013	2014	There-after	Total
Capital and other purchase commitments	$ 315	$ 36	$ 7	$ 8	$ 1	$ 18	$ 385
Purchased power and fuel:							
Electricity purchases	324	89	65	66	63	521	1,128
Capacity contracts	22	21	20	20	20	38	141
Public Utility Districts	7	7	5	5	5	34	63
Natural gas	97	36	17	16	13	29	208
Coal and transportation	20	17	3	3	-	-	43
Operating leases	8	9	9	10	10	234	280
Total	$ 793	$ 215	$ 126	$ 128	$ 112	$ 874	$ 2,248

Capital and other purchase commitments - Certain commitments have been made for capital and other purchases for 2010 and beyond. Such commitments include those related to hydro license agreements, Biglow Canyon Phase III, upgrades to production, distribution and transmission facilities, decommissioning activities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

Electricity purchases and Capacity contracts - PGE has power purchase contracts with counterparties, which expire at varying dates through 2035, and power capacity contracts through 2016. As of December 31, 2009, PGE has power sale contracts with counterparties of approximately $78 million in 2010, $5 million in 2011, and $4 million in 2012.

PGE has two long-term power exchange contracts. One exchange contract is with a summer-peaking California utility to help meet the Company’s winter-peaking power requirements and expires in 2012. As of December 31, 2009, PGE was owed 230 MWh of electricity, all of which is expected to be delivered by the end of February 2010. The other exchange contract is with a winter-peaking Northwest utility to help meet the Company’s summer-peaking power requirements and expires in 2011. As of December 31, 2009, PGE owed 8,414 MWh of electricity, all of which is expected to be delivered by the end of February 2010.

Public Utility Districts - PGE has long-term power purchase contracts with certain public utility districts in the state of Washington and with the City of Portland, Oregon. The Company is required to pay its proportionate share of the operating and debt service costs of the hydroelectric projects whether or not they are operable. Selected information regarding these projects is summarized as follows (dollars in millions):

	Revenue Bonds as of December 31, 2009	PGE Share Output	PGE Share Capacity (in MW)	Contract Expiration	PGE Cost, including Debt Service 2009	PGE Cost, including Debt Service 2008
Rocky Reach	$ 333	12.0 %	156	2011	$ 8	$ 9
Priest Rapids and Wanapum	649	11.5	233	2052	17	14
Wells	176	19.4	159	2018	8	8
Portland Hydro	15	100.0	36	2017	4	3

Under contracts with the public utility districts, PGE has acquired a percentage of the output (Allocation) of Rocky Reach, Priest Rapids and Wanapum, and Wells. The contracts provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro rata share of the output and operating and debt service costs of the defaulting purchaser. For Rocky Reach and Wells, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage Allocation. For Priest Rapids and Wanapum, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any outstanding debt.

As the individual contracts related to Priest Rapids and Wanapum expired, the terms governing the output of each hydroelectric project are included in one long-term power purchase agreement. Effective November 1, 2009, the last separate contract expired, resulting in both hydroelectric projects being included in one contract. As a result, the debt service amounts previously reported for 2008 and 2007 for Priest Rapids and Wanapum separately were combined to conform with the 2009 presentation.

Natural gas - PGE has agreements for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities. The Company also has a natural gas storage agreement, which expires April 2017, for the purpose of fueling the Company's Port Westward and Beaver generating plants.

Coal and transportation - PGE has coal and related rail transportation agreements with take-or-pay provisions, which expire at various dates through 2013.

Operating leases - PGE has various operating leases associated with its headquarters and certain of its production, transmission, and support facilities. The majority of the future minimum operating lease payments presented in the table above consist of (1) the corporate headquarters lease, which expires in 2018, but includes renewal period options through 2043, and (2) the Port of St. Helens land lease, where PGE's Beaver and Port Westward generating plants operate, which expires in 2096. Rent expense was $8 million in both 2009 and 2008.

The future minimum operating lease payments presented is net of sublease income of $3 million in 2010 and 2011, $2 million in 2012, and $1 million in 2013 and 2014. Sublease income is classified as Miscellaneous income in the statements of income and was $3 million in both 2009 and 2008.

Guarantees

PGE entered into a sale transaction in 1985 in which it sold an undivided 15% interest in Boardman and a 10.714% undivided interest in the Pacific Northwest Intertie (Intertie) transmission line (jointly the Boardman Assets) to an unrelated third party (Purchaser). The Purchaser leased the Boardman Assets to a lessee (Lessee) unrelated to PGE or the Purchaser. Concurrently, PGE assigned to the Lessee certain agreements for the sale of power and transmission services from Boardman and the Intertie (P&T Agreements) to a regulated electric utility (Utility) unrelated to PGE, the Purchaser, or the Lessee. The P&T Agreements expire on December 31, 2013. The payments by the Utility under the P&T Agreements exceed the payments to be made by the Lessee to the Purchaser under the lease. In exchange for PGE undertaking certain obligations of the Lessee under the lease, the Lessee reassigned to PGE certain rights, including the excess payments, under the P&T Agreements. However, in the event that the Utility defaults on the payments it owes under the P&T Agreements, PGE may be required to pay the damages owed by the Lessee to the Purchaser under the lease. Assuming no recovery from the Utility and no reduction in damages from mitigating sales or leases related to the Boardman Assets and P&T Agreements, the maximum amount that would be owed by PGE in 2010 is approximately $125 million. Management believes that circumstances that could result in such amount, or any lesser amount, being owed by the Company are remote.

PGE enters into financial agreements and power purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on PGE's historical experience and the evaluation of the specific indemnities. As of December 31, 2009, management believes the likelihood is remote that PGE would be required to perform or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the balance sheets with respect to these indemnifications.

NOTE 15: JOINTLY-OWNED PLANT

PGE has interests in three jointly-owned generating facilities. Under the joint operating agreements, each participating owner is responsible for financing its share of construction, operating and leasing costs. PGE's proportionate share of direct operating and maintenance expenses of the facilities is included in the corresponding operating and maintenance expense categories in the statements of income.

As of December 31, 2009, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation (1)	Construction Work In Progress
Boardman	65.00%	1980	$ 434	$ 274	$ 5
Colstrip	20.00%	1986	494	315	3
Pelton/Round Butte	66.67%	1958/1964	131	49	84
Total			$ 1,059	$ 638	$ 92

(1) Excludes asset retirement obligations and accumulated asset retirement removal costs.

NOTE 16: CONTINGENCIES

Legal Matters

Trojan Investment Recovery

Background. In 1993, PGE closed the Trojan Nuclear Plant as part of the Company's least cost planning process. PGE sought full recovery of, and a rate of return on, its Trojan plant costs in a general rate case filing with the OPUC. In 1995, the OPUC issued a general rate order that granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan plant costs.

Court Proceedings on OPUC Authority to Grant Recovery of Return on Trojan Investment. Numerous challenges, appeals and reviews were subsequently filed in the Marion County Circuit Court (Circuit Court), the Oregon Court of Appeals, and the Oregon Supreme Court on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. The primary plaintiffs in the litigation were the Citizens' Utility Board (CUB) and the Utility Reform Project (URP). The Oregon Court of Appeals issued an opinion in 1998, which upheld the OPUC's authorization of PGE's recovery of the Trojan investment, but stated that the OPUC did not have the authority to allow PGE to recover a return on the Trojan investment and remanded the case to the OPUC.

Settlement of Court Proceedings on OPUC Authority. In 2000, PGE, CUB, and the staff of the OPUC entered into agreements to settle the litigation related to PGE's recovery of, and return on, its investment in the Trojan plant. The URP did not participate in the settlement, which was approved by the OPUC in September 2000. The settlement allowed PGE to remove from its balance sheet the remaining before-tax investment in Trojan of approximately $180 million at September 30, 2000, along with several largely offsetting regulatory liabilities.

Challenge to Settlement of Court Proceeding. The URP filed a complaint with the OPUC challenging the settlement agreements and the OPUC's September 2000 order. In March 2002, the OPUC issued an order (2002 Order) denying all of the URP's challenges, and approving the accounting and ratemaking elements of the 2000 settlement. On October 10, 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the 2002 Order to the OPUC for reconsideration.

Remand of 2002 Order. As a result of the Oregon Court of Appeals remand of the 2002 Order, the OPUC considered whether the OPUC has authority to engage in retroactive ratemaking and what prices would have been if, in 1995, the OPUC had interpreted the law to prohibit a return on the Trojan investment. On September 30, 2008, the OPUC issued an order that requires PGE to refund $15.4 million, plus interest at 9.6% from September 30, 2000, to customers who received service from PGE during the period October 1, 2000 to September 30, 2001. The order also provides that the total refund amount will accrue interest at 9.6% from October 1, 2008 until all refunds are issued to customers. The URP and the plaintiffs in the class actions described below have separately appealed the order to the Oregon Court of Appeals.

The $15.4 million amount, plus accrued interest, resulted in a total refund of $33.1 million as of September 30, 2008. As a result of the September 30, 2008 order, PGE recorded, as a regulatory liability, the total refund due to customers of $33.1 million, which reduced 2008 revenues. As of December 31, 2009, the Company had substantially completed the distribution of the refund.

Class Actions. In a separate legal proceeding, two class action suits were filed in Circuit Court against PGE on January 17, 2003 on behalf of two classes of electric service customers (the Class Action Plaintiffs). The cases seek to represent PGE customers during the period from April 1, 1995 to October 1, 2000. The suits seek damages of

$260 million plus interest as a result of the inclusion of a return on investment of Trojan in the prices PGE charged its customers.

On December 14, 2004, the judge granted the Class Action Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. On March 3, 2005 and March 29, 2005, PGE filed two Petitions for an Alternative Writ of Mandamus with the Oregon Supreme Court, asking the Court to take jurisdiction and command the trial judge to dismiss the complaints or to show cause why they should not be dismissed, and seeking to overturn the Class Certification.

On August 31, 2006, the Oregon Supreme Court issued a ruling on PGE's Petitions for Alternative Writ of Mandamus, abating the class action proceedings until the OPUC responded with respect to the 2002 Order (described above). The Oregon Supreme Court concluded that the OPUC has primary jurisdiction to determine what, if any, remedy it can offer to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment PGE collected in prices for the period from April 1, 1995 through October 1, 2000. The Oregon Supreme Court further stated that if the OPUC determined that it can provide a remedy to PGE's customers, then the class action proceedings may become moot in whole or in part. The Oregon Supreme Court further stated that, if the OPUC determined that it cannot provide a remedy, the court system may have a role to play. The Oregon Supreme Court also ruled that the plaintiffs retain the right to return to the Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings.

On October 5, 2006, the Circuit Court issued an Order of Abatement in response to the ruling of the Oregon Supreme Court, abating the class actions, but inviting motions to lift the abatement after one year. On October 17, 2007, the plaintiffs filed a motion to lift the abatement. On February 10, 2009, the Circuit Court judge denied the plaintiffs' motion to lift the abatement.

Management cannot predict the ultimate outcome of the above matters. However, it believes that these matters will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on the results of operations and cash flows for a future reporting period.

Complaint and Application for Deferral – Income Taxes

On October 5, 2005, the URP and another party (together, the Complainants) filed a Complaint and an Application for Deferred Accounting with the OPUC alleging that, since the September 2, 2005 effective date of Oregon Senate Bill 408 (SB 408), PGE's rates were not just and reasonable and were in violation of SB 408 because they contained approximately $92.6 million in annual charges for state and federal income taxes that are not being paid to any governmental entity. The Complaint and Application for Deferred Accounting requested that the OPUC order the creation of a deferred account for all amounts charged to customers since September 2, 2005 for state and federal income taxes, less amounts actually paid by or on behalf of PGE to the federal and state governments for income taxes.

On August 14, 2007, the OPUC issued an order granting the Application for Deferred Accounting for the period from October 5, 2005 through December 31, 2005 (Deferral Period). The OPUC's order also dismissed the Complaint, without prejudice, on grounds that it was superfluous to the Complainants' request for deferred accounting. The order required that PGE calculate the amounts applicable to the Deferral Period, along with calculations of PGE's earnings and the effect of the deferral on the Company's return on equity. The order also provided that the OPUC would review PGE's earnings at the time it considered amortization of the deferral.

On December 1, 2007, PGE filed its report as required by the OPUC. In the report, PGE determined that (i) the amount of any deferral would be between zero and $26.6 million; and (ii) PGE's earnings over the twelve-month period ended

September 30, 2006 would preclude any refund.

On August 18, 2009, the OPUC issued an order that denied amortization of any deferral in this matter, based on a review of PGE's earnings over the 12-month period ended September 30, 2006. On October 16, 2009, plaintiffs filed an appeal of the August 18, 2009 order with the Oregon Court of Appeals.

Management cannot predict the ultimate outcome of this matter. However, management believes this matter will not have a material adverse effect on PGE's financial condition, results of operations or cash flows.

Turlock Irrigation District Claim

PGE and Power Resources Cooperative (PRC) are parties to an Ownership and Operation Agreement (OOA), pursuant to which PRC is entitled to ten percent of the power generated at Boardman. In 1992, PRC entered into a power purchase agreement with Turlock Irrigation District (Turlock) in which PRC agreed to provide Turlock with its share of the Boardman output. In October 2005, Boardman experienced an outage that extended into 2006.

Turlock subsequently filed a lawsuit against PGE in Multnomah County Circuit Court in the state of Oregon, alleging breach of contract, negligence, and gross negligence, seeking damages in excess of $15 million as a result of having to purchase power in the open market to replace lost output from Boardman during the outage. The complaint further alleges that PRC assigned its litigation rights relating to the outage to Turlock pursuant to an assignment agreement executed in 2007.

PGE sought and received an order joining PRC as a necessary party to the litigation in view of PRC's position as a Boardman co-owner and assignor of Turlock's rights. PRC intervened as a plaintiff, also alleging breach of contract and damages in the amount alleged by Turlock, for the purpose of reimbursing Turlock for those expenses. In September 2009, PGE filed a motion for summary judgment, alleging that Turlock lacked standing to bring an action against PGE and that the OOA bars claims based on negligence.

In November 2009, the Court denied PGE's motion for summary judgment and set a trial schedule. In doing so, the court ruled that Turlock has standing to bring a claim against PGE under the OOA, that negligence claims are not barred under the OOA, and that damages based on economic loss are recoverable under a tort claim.

Management cannot predict the outcome of this matter. Management believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE's results of operations and cash flows in future reporting periods.

City of Glendale Claim

In September 1988, PGE and the City of Glendale, California (Glendale) entered into a Long-Term Power Sale and Exchange Agreement (Agreement) pursuant to which Glendale purchases up to 20 MW of firm system capacity from PGE as scheduled by Glendale. The Agreement remains effective until 2012.

In 2005, Glendale disputed the price that PGE had been charging for power under the contract and requested refunds. In addition, Glendale asserted that the closure of Trojan was the equivalent of a sale of a PGE resource, triggering a duty under the Agreement to renegotiate price terms.

On August 25, 2005, PGE filed a complaint in the U.S. District Court for the District of Oregon against Glendale, requesting a declaratory ruling that PGE does not owe Glendale any refunds under the Agreement and that the closure of

Trojan was not a "sale" requiring PGE to renegotiate price terms with Glendale.

In response to PGE's complaint, Glendale asserted that the FERC had jurisdiction over the matter and requested that the FERC direct PGE to adjust the prices under the Agreement and refund to Glendale approximately $23.3 million plus interest. On December 19, 2005, the FERC dismissed the proceeding. Following dismissal of the FERC proceeding, Glendale filed a motion in the District Court case to dismiss PGE's complaint. The Court denied Glendale's motion. Glendale then filed an answer and counterclaim against PGE seeking approximately $23.3 million, plus interest. Subsequently, each party filed a motion for summary judgment. In July 2009, the Court granted PGE's motion for summary judgment in substantial part and denied Glendale's motion for summary judgment. As a result of the Court's ruling, the pricing issues relating to Glendale's assertion of a right to a refund under the Agreement remain in the case for trial, but Glendale's claim that the closure of Trojan required a renegotiation of pricing under the Agreement has been dismissed. Until further discovery has been conducted, the Company is unable to estimate the dollar amount that remains at issue in Glendale's refund claim.

Management cannot predict the outcome of this matter. Management believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE's results of operations and cash flows in future reporting periods.

Regulatory Matters

Pacific Northwest Refund Proceeding

On July 25, 2001, the FERC called for a preliminary evidentiary hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001 (Pacific Northwest Refund proceeding). During that period, PGE both sold and purchased electricity in the Pacific Northwest. In September 2001, upon completion of hearings, the appointed administrative law judge issued a recommended order that the claims for refunds be dismissed. In June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. Parties appealed various aspects of the FERC order to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

On August 24, 2007, the Ninth Circuit issued its decision, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to (i) address the new market manipulation evidence in detail and account for it in any future orders regarding the award or denial of refunds in the proceedings, (ii) include sales to CERS in its analysis, and (iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the FERC's ultimate decision to deny refunds. After denying requests for rehearing, the Ninth Circuit on April 16, 2009 issued a mandate giving immediate effect to its August 24, 2007 order remanding the case to the FERC.

Since issuance of the mandate, certain parties proposing refunds have filed pleadings with the FERC suggesting procedures on remand, attempting to initiate new proceedings, and containing additional evidence that they assert shows market-wide manipulation that justifies refunds from early in 2000. Parties opposing refunds, including PGE, have filed various pleadings that contest allegations of market-wide manipulation and urge the FERC to reaffirm, with a more detailed explanation of its consideration of market manipulation claims, its previous decision not to initiate proceedings to order refunds.

On September 4, 2009, various parties, including PGE, filed a petition for a writ of certiorari with the U.S. Supreme Court requesting that the Supreme Court review the decision of the Ninth Circuit in the Pacific Northwest Refund proceeding. In January 2010, the Supreme Court denied the petition for a writ of certiorari.

The settlement between PGE and certain other parties in the California refund case in Docket No. EL00-95, et seq., approved by the FERC on May 17, 2007, resolved all claims as between PGE and the California parties named in the settlement as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 21, 2001, but does not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

Management cannot predict the outcome of the Pacific Northwest Refund proceeding, or whether the FERC will order refunds in this proceeding, and if so, how such refunds would be calculated. Management believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE's results of operations and cash flows in future reporting periods.

FERC Investigation

In May 2008, PGE received a notice of a preliminary non-public investigation from the FERC Division of Investigations concerning PGE's compliance with its Open Access Transmission Tariff. The investigation involves certain issues identified during an audit by FERC staff.

Management cannot predict the final outcome of the investigation or what actions, if any, the FERC will take or require the Company to take. Management believes that the outcome will not have a material adverse impact on the financial condition, results of operations, or cash flows of the Company.

<u>Environmental Matters</u>

Portland Harbor

A 1997 investigation by the U.S. Environmental Protection Agency (EPA) of a segment of the Willamette River known as the Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included this segment on the federal National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act as a federal Superfund site and listed sixty-nine Potentially Responsible Parties (PRPs). PGE was included among the PRPs as it has historically owned or operated property near the river.

The Portland Harbor site is currently undergoing a remedial investigation and feasibility study (RI/FS) pursuant to an Administrative Order on Consent (AOC) between the EPA and several PRPs, not including PGE. In the AOC, the EPA determined that the RI/FS would focus on a segment of the river approximately 5.7 miles in length.

On January 22, 2008, PGE received a Section 104(e) Information Request from the EPA requiring the Company to provide information concerning its properties in or near the segment of the river being examined in the RI/FS, as well as several miles beyond that 5.7 mile segment, to which PGE has responded. During 2009, the EPA sent General Notice Letters to 15 additional PRPs.

The EPA will determine the boundaries of the site at the conclusion of the RI/FS in a Record of Decision, now expected in 2012, in which it will document its findings and select a preferred cleanup alternative.

Sufficient information is currently not available to determine the total cost of any required investigation or remediation of the Portland Harbor site or the liability of PRPs, including PGE. Management cannot predict the ultimate outcome of this matter. Management believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE's results of operations and cash flows in future reporting periods.

The OPUC issued an order authorizing the deferral, for later ratemaking treatment, of incremental investigation and remediation costs related to the Portland Harbor site incurred during the twelve-month period ended March 31, 2009. PGE requested a second twelve-month deferral period beginning April 1, 2009, however subsequently withdrew the request, opting instead to seek recovery of any incurred costs in future rate proceedings. As of December 31, 2009, the Company had not deferred any costs related to Portland Harbor.

Harbor Oil

Harbor Oil, Inc. (Harbor Oil), located in north Portland, was utilized by PGE to process used oil from the Company's power plants and electrical distribution system from at least 1990 until 2003. Harbor Oil continues to be utilized by other entities for the processing of used oil and other lubricants.

In 1974 and 1979, major oil spills occurred at the Harbor Oil site. Elevated levels of contaminants, including metals, pesticides, and polychlorinated biphenyls, have been detected at the site. On September 29, 2003, the Harbor Oil facility was included on the National Priority List as a federal Superfund site.

PGE received a Special Notice Letter for RI/FS from the EPA, dated June 27, 2005, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. On May 31, 2007, an Administrative Order on Consent was signed by the EPA and six other parties, including PGE, to implement an RI/FS at the Harbor Oil site. The EPA has approved an RI/FS work plan. On-site sampling commenced in 2008 and has yet to be completed.

Sufficient information is currently not available to determine the total cost of investigation and remediation of the Harbor Oil site or the liability of the PRPs, including PGE. Management cannot predict the ultimate outcome of this matter. Management believes that the outcome of this matter will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE's results of operations and cash flows in future reporting periods.

The OPUC issued an order authorizing the deferral, for later ratemaking treatment, of incremental costs related to RI/FS work and any resulting remediation costs incurred in relation to the Harbor Oil site during the twelve-month period ended March 31, 2009. PGE requested a second twelve-month deferral period beginning April 1, 2009, however subsequently withdrew the request, opting instead to seek recovery of any recovery of any incurred costs in future rate proceedings. As of December 31, 2009, the Company had not deferred any costs related to Harbor Oil.

Other Matters

PGE is subject to other regulatory, environmental, and legal proceedings that arise from time to time in the ordinary course of its business, which may result in adverse judgments against the Company. Although management currently believes that resolution of such matters will not have a material adverse effect on its financial position, results of operations, or cash flows, these matters are subject to inherent uncertainties and management's view of these matters may change in the future.

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(6,827,951)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				403,930
3	Preceding Quarter/Year to Date Changes in Fair Value				1,315,217
4	Total (lines 2 and 3)				1,719,147
5	Balance of Account 219 at End of Preceding Quarter/Year				(5,108,804)
6	Balance of Account 219 at Beginning of Current Year				(5,108,804)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(966,975)
8	Current Quarter/Year to Date Changes in Fair Value				433,617
9	Total (lines 7 and 8)				(533,358)
10	Balance of Account 219 at End of Current Quarter/Year				(5,642,162)

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	2,383,421		(4,444,530)		
2	(1,840,069)		(1,436,139)		
3			1,315,217		
4	(1,840,069)		(120,922)	87,175,123	87,054,201
5	543,352		(4,565,452)		
6	543,352		(4,565,452)		
7	(433,617)		(1,400,592)		
8			433,617		
9	(433,617)		(966,975)	95,365,873	94,398,898
10	109,735		(5,532,427)		

Schedule Page: 122(a)(b) Line No.: 3 Column: e

PGE records a regulatory asset or regulatory liability pursuant to ASC 980 to offset the effects of unrealized gains and losses from changes in the fair value of Price Risk Management Assets and Liabilities designated as cash flow hedges. Consists of net amount of the update to the actuarial valuation of the non-qualified benefit plans, $(524,852), and cash flow hedges on natural gas forward and swap contracts, $1,840,069.

Schedule Page: 122(a)(b) Line No.: 7 Column: e

Comprised of the net amount of the update to the actuarial valuation of non-qualified benefit plans.

Schedule Page: 122(a)(b) Line No.: 8 Column: e

PGE records a regulatory asset or regulatory liability pursuant to ASC 980 to offset the effects of unrealized gains and losses from changes in the fair value of Price Risk Management Assets and Liabilities designated as cash flow hedges. Consists of ASC 815 Unrealized Mark-to-Market Gain of $716,723 on natural gas forward and swap contracts and Deferred Taxes of $(283,106).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	5,581,783,959	5,581,783,959
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,581,783,959	5,581,783,959
9	Leased to Others		
10	Held for Future Use	12,959,163	12,959,163
11	Construction Work in Progress	406,591,842	406,591,842
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	6,001,334,964	6,001,334,964
14	Accum Prov for Depr, Amort, & Depl	2,684,786,163	2,684,786,163
15	Net Utility Plant (13 less 14)	3,316,548,801	3,316,548,801
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,563,026,345	2,563,026,345
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	121,759,818	121,759,818
22	Total In Service (18 thru 21)	2,684,786,163	2,684,786,163
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,684,786,163	2,684,786,163

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

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
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					31
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					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
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			11
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			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	68,120,517	3,796,878
4	(303) Miscellaneous Intangible Plant	137,965,995	7,499,787
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	206,086,512	11,296,665
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,126,752	
9	(311) Structures and Improvements	215,389,241	290,265
10	(312) Boiler Plant Equipment	427,142,470	6,865,818
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	125,699,830	10,377,182
13	(315) Accessory Electric Equipment	46,274,157	46,597
14	(316) Misc. Power Plant Equipment	12,281,713	102,459
15	(317) Asset Retirement Costs for Steam Production	750,598	3,571,605
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	831,664,761	21,253,926
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	5,763,398	288,412
28	(331) Structures and Improvements	33,245,886	1,637,192
29	(332) Reservoirs, Dams, and Waterways	148,044,878	2,600,877
30	(333) Water Wheels, Turbines, and Generators	45,522,509	27,769
31	(334) Accessory Electric Equipment	13,369,153	324,313
32	(335) Misc. Power PLant Equipment	1,845,979	23,739
33	(336) Roads, Railroads, and Bridges	8,551,367	225,996
34	(337) Asset Retirement Costs for Hydraulic Production	4,276	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	256,347,446	5,128,298
36	D. Other Production Plant		
37	(340) Land and Land Rights	48,946	
38	(341) Structures and Improvements	64,180,599	10,256,787
39	(342) Fuel Holders, Products, and Accessories	152,014,364	2,625,978
40	(343) Prime Movers		
41	(344) Generators	578,524,162	298,277,381
42	(345) Accessory Electric Equipment	45,482,988	6,739,303
43	(346) Misc. Power Plant Equipment	8,818,635	320,318
44	(347) Asset Retirement Costs for Other Production	859,684	718,638
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	849,929,378	318,938,405
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,937,941,585	345,320,629

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	11,032,948	124,982
49	(352) Structures and Improvements	14,834,416	473,055
50	(353) Station Equipment	196,673,606	9,296,378
51	(354) Towers and Fixtures	46,771,478	142,298
52	(355) Poles and Fixtures	22,231,462	4,676
53	(356) Overhead Conductors and Devices	58,571,445	10,674,381
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	286,332	
57	(359.1) Asset Retirement Costs for Transmission Plant	53,039	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	350,454,726	20,715,770
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	12,369,873	680,740
61	(361) Structures and Improvements	33,099,731	470,244
62	(362) Station Equipment	279,830,009	17,057,244
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	269,296,201	15,727,862
65	(365) Overhead Conductors and Devices	431,566,434	27,843,498
66	(366) Underground Conduit	15,791,045	
67	(367) Underground Conductors and Devices	530,743,072	28,603,933
68	(368) Line Transformers	264,965,825	8,744,432
69	(369) Services	344,533,301	8,203,925
70	(370) Meters	62,022,327	68,467,434
71	(371) Installations on Customer Premises	376,133	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	53,367,631	1,381,755
74	(374) Asset Retirement Costs for Distribution Plant	460,131	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,298,421,713	177,181,067
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	4,873,150	
87	(390) Structures and Improvements	56,877,819	1,236,216
88	(391) Office Furniture and Equipment	45,553,352	10,544,172
89	(392) Transportation Equipment	36,205,116	7,067,285
90	(393) Stores Equipment	824,775	
91	(394) Tools, Shop and Garage Equipment	10,235,769	332,771
92	(395) Laboratory Equipment	11,197,615	907,704
93	(396) Power Operated Equipment	42,000,998	2,273,159
94	(397) Communication Equipment	51,444,928	7,451,598
95	(398) Miscellaneous Equipment	197,648	1,972
96	SUBTOTAL (Enter Total of lines 86 thru 95)	259,411,170	29,814,877
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	64,488	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	259,475,658	29,814,877
100	TOTAL (Accounts 101 and 106)	5,052,380,194	584,329,008
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	5,052,380,194	584,329,008

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			71,917,395		3
3,446,694			142,019,088		4
3,446,694			213,936,483		5
					6
					7
			4,126,752		8
34,828			215,644,678		9
801,493			433,206,795		10
					11
2,696,941			133,380,071		12
			46,320,754		13
19,143			12,365,029		14
			4,322,203		15
3,552,405			849,366,282		16
					17
					18
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					26
4,184			6,047,626		27
100,322		-29,346	34,753,410		28
33,316			150,612,439		29
			45,550,278		30
4,509		7,673	13,696,630		31
57,341			1,812,377		32
			8,777,363		33
			4,276		34
199,672		-21,673	261,254,399		35
					36
			48,946		37
7,863		25,369,611	99,799,134		38
362,125		-37,587,029	116,691,188		39
					40
68,073		9,088,470	885,821,940		41
		-7,242,224	44,980,067		42
		-1,413,971	7,724,982		43
			1,578,322		44
438,061		-11,785,143	1,156,644,579		45
4,190,138		-11,806,816	2,267,265,260		46

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		-31,068	11,126,862		48
10,402		-58,094	15,238,975		49
237,226		-4,909,856	200,822,902		50
			46,913,776		51
631,444		-4,455,086	17,149,608		52
1,387,374		4,455,086	72,313,538		53
					54
					55
			286,332		56
			53,039		57
2,266,446		-4,999,018	363,905,032		58
					59
		73,096	13,123,709		60
10,662		-367,809	33,191,504		61
1,094,653		16,202,727	311,995,327		62
					63
1,372,644			283,651,419		64
2,238,250			457,171,682		65
29,055			15,761,990		66
391,784			558,955,221		67
1,714,471		-3,063	271,992,723		68
120,508			352,616,718		69
24,750,801		-2,262	105,736,698		70
			376,133		71
					72
218,993			54,530,393		73
			460,131		74
31,941,821		15,902,689	2,459,563,648		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			4,873,150		86
721,145			57,392,890		87
5,686,404		105,358	50,516,478		88
1,949,158			41,323,243		89
349,513		17,803	493,065		90
25,210		37,201	10,580,531		91
157,199		11,699	11,959,819		92
2,909,584			41,364,573		93
1,321,637		804,182	58,379,071		94
33,392			166,228		95
13,153,242		976,243	277,049,048		96
					97
			64,488		98
13,153,242		976,243	277,113,536		99
54,998,341		73,098	5,581,783,959		100
					101
					102
					103
54,998,341		73,098	5,581,783,959		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Damascus, Clackamas County, OR	2007	Various	543,591
3	Marquam, Multnomah County, OR	2007	Various	3,112,750
4	Sewell, Washington County, OR	2008	Various	2,588,699
5	Sunset, Washington County, OR	2007	Various	1,783,648
6	Teufel, Washington County, OR	2007	Various	649,143
7	Scholls Ferry, Washington County, OR	2009	Various	1,763,748
8	Shute Road, Washington County, OR	2009	Various	1,720,108
9	Highway 26 Easements, Washington County, OR	2009	Various	278,500
10	Sewell Easement, Washington County, OR	2009	Various	331,186
11	Other Land and Land Rights (7 in Number)	Various	Various	187,790
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
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45				
46				
47	Total			12,959,163

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Biglow Canyon Windfarm Generation Project (Phase 3)	205,026,245
2	Pelton/Round Butte - Selective Water Withdrawal	79,289,331
3	Clackamas River Hydro FERC Licensing Project	62,501,688
4	Advanced Metering Infrastructure	5,463,817
5	California-Oregon Intertie (COI) - Transmission Line Upgrade	4,624,301
6	Port Westward- Expand Substation For Beaver Integration	3,060,451
7	Work Management - Software Purchase	2,802,213
8	Boardman- Purchase Spare Generator Rotor	2,653,273
9	Financial System - Software Purchase	2,263,089
10	River District - Install Vaults	2,053,209
11	Beaver- Replace Blades in GT-3 Compressor	2,041,537
12	Colstrip- Install Mercury Controls For Units 3 & 4	1,987,663
13	Pelton/Round Butte - FERC License Requirements	1,880,126
14	Sullivan Fish Passage	1,847,092
15	Harmony Substation - Replace Transformer WR-1	1,829,866
16	Sunset Substation - Install 50 MVA Transformer	1,805,361
17	Boardman- Excess Capital From SDG&E Contract	1,465,754
18	PGE Web - Functional Enhancements And Improvements	1,454,594
19	Portable Substation Number 7 - Rewind Transformer	1,093,452
20	Wilsonville Substation - Convert To 115-Kv	1,044,157
21	Keeler Substation BPA - Install New 230-Kv Breaker	1,009,008
22	Mcloughlin Substation - Replace Impedance Relays	978,803
23	River Mill - Install Downstream Migrant Surface Collector	944,686
24	PSC Computer Room Emergency Generator & HVAC Upgrade	842,614
25	Colstrip Plant - Capital Projects	780,769
26	Compliance Automation - Software Purchase	680,033
27	Alder Substation - Install WR-2 Transformer	541,329
28	Pelton/Round Butte - Indian Park Improvements	508,070
29	Millcreek Substation - Install SCADA System	491,045
30	Boardman - Install Gear Driven Coal Orifices	462,523
31	EM&C Substation Engineering- Work Management Software	448,299
32	Pelton/Round Butte - Day Use Area Improvements	399,979
33	Bald Peak Communication Station - Alarm For Communications	363,052
34	Fitness - Software Purchase	359,045
35	Pelton/Round Butte - Perry South Campground Improvements	337,354
36	North Fork PME - Extend Migrant Fish Passage	308,508
37	Hillsboro Substation - Replace SCADA System	302,612
38	Oak Grove to Timothy Lake Microwave Upgrade	292,758
39	Beaver-Alston 230-Kv Transmission Pole Replacement	267,206
40	Dispatchable Generation - Installation	263,514
41	Coyote Springs 1 - Combustion Casing Replacement	247,967
42	Harmony Substation - Replace Motor Operated Disconnect Switches With Circuit Switchers	242,925
43	TOTAL	406,591,842

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Upgrade PBX Software	233,514
2	Dispatchable Generation - Installation	226,650
3	Coyote Springs - Process Portal Upgrade for DCS	226,090
4	Pelton/Round Butte - Upgrade Pelton Fish Trap	211,844
5	Dispatchable Generation - PSC Backup Generator	211,084
6	Millcreek Substation - Arc Flash Mitigation	209,683
7	Customer Callback - Software Purchase	206,099
8	Bethel Substation - Replace Relays	205,787
9	Pleasant Valley Substation - Add 28 MVA Transformer WR-2	201,769
10	Culver Substation - Install Fiber Optics	200,361
11	Boardman - Optimize Intake Temperature	168,198
12	Pelton - Install New Boat Dock at Pelton Park	166,971
13	Scoggins Substation - Add Circuit Switchers	158,877
14	North Fork - Improve Down Stream Fish Migration Structure	158,111
15	Canyon Substation - Install Switchers & Replace RPD'S	151,330
16	River Mill PME - Construct Migrant Fish Pipe Sampling Facility	145,226
17	Dunn's Corner Substation - Relocate Relays From Bull Run Switchyard	139,076
18	Mcloughlin Substation - Expand Metal Fencing	138,810
19	Canyon Substation - Install Breaker Rack System	137,777
20	Gresham Substation - Replace Line Relays For Breaker W-182	132,411
21	Rivergate South Substation - Replace Capacitor Banks 4, 5, And 6	131,279
22	Harborton Substation - Install Oil Spill Containment System	129,427
23	St. Mary's East Substation - Install SCADA System	126,064
24	Pelton/Round Butte- Install Air Gap Monitors	124,392
25	North Fork PME - Install Adult Sorting Facility In Fish Ladder	117,039
26	North Fork PME - Inspect/Repair/Upgrade Migrant Fish Pipe	114,447
27	Beaver - Install New Inlet Gas Pipe Section From KB Pipeline	112,938
28	Pelton/Round Butte - Entrance Road Asphalt Paving Improvement	110,372
29	Salem Service Center - Asphalt Replacement	109,847
30	North Fork - Pave Small Fry Lake Parking Area	108,776
31	Work Orders < $100,000	4,518,275
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	406,591,842

Schedule Page: 216 Line No.: 2 Column: a
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.

Schedule Page: 216 Line No.: 8 Column: a
Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing BSC, LLC. Respondant's 65% share of jointly owned costs is reported.

Schedule Page: 216 Line No.: 12 Column: a
Jointly owned with Northwestern Energy LLC, PP&L Montana, LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Respondent's 20% share of jointly owned costs is reported.

Schedule Page: 216 Line No.: 13 Column: a
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.

Schedule Page: 216 Line No.: 17 Column: a
Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing NSC, LLC. Respondent's 65% share of jointly owned costs is reported.

Schedule Page: 216 Line No.: 21 Column: a
Switching Only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.

Schedule Page: 216 Line No.: 25 Column: a
Jointly owned with Northwestern Energy LLC, PP&L Montana, LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Repondent's 20% share of jointly owned costs is reported.

Schedule Page: 216 Line No.: 28 Column: a
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.

Schedule Page: 216 Line No.: 30 Column: a
Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing BSC, LLC. Respondent's 65% share of jointly owned costs is reported.

Schedule Page: 216 Line No.: 32 Column: a
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.

Schedule Page: 216 Line No.: 35 Column: a
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.

Schedule Page: 216.1 Line No.: 4 Column: a
Jointly owned with the Confederated Tribes of the Warm Springs Resevation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.

Schedule Page: 216.1 Line No.: 11 Column: a
Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing BSC, LLC. Respondent's 65% share of the jointly owned costs is reported.

Schedule Page: 216.1 Line No.: 12 Column: a
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.

Schedule Page: 216.1 Line No.: 24 Column: a
Jointly owned with the confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.

Schedule Page: 216.1 Line No.: 28 Column: a
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	2,433,510,863	2,433,510,863		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	184,241,239	184,241,239		
4	(403.1) Depreciation Expense for Asset Retirement Costs	53,948	53,948		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	5,327,837	5,327,837		
7	Other Clearing Accounts	703,786	703,786		
8	Other Accounts (Specify, details in footnote):	-2,299,983	-2,299,983		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	188,026,827	188,026,827		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	51,547,460	51,547,460		
13	Cost of Removal	8,433,956	8,433,956		
14	Salvage (Credit)	1,470,071	1,470,071		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	58,511,345	58,511,345		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,563,026,345	2,563,026,345		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	582,361,196	582,361,196		
21	Nuclear Production				
22	Hydraulic Production-Conventional	121,402,147	121,402,147		
23	Hydraulic Production-Pumped Storage				
24	Other Production	276,990,794	276,990,794		
25	Transmission	154,106,563	154,106,563		
26	Distribution	1,308,208,151	1,308,208,151		
27	Regional Transmission and Market Operation				
28	General	119,957,494	119,957,494		
29	TOTAL (Enter Total of lines 20 thru 28)	2,563,026,345	2,563,026,345		

Schedule Page: 219   Line No.: 8   Column: c

Represents Beaver 8 amortization, per OPUC Order No. 04-740. Fully offset in FERC 182.3 - Other Regulatory Assets.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	121 SW Salmon Street Corporation			
2	Common Stock	04/01/75		1,000
3	Equity in Earnings			57,213
4	Sub - TOTAL			58,213
5				
6	Salmon Springs Hospitality Group			
7	Common Stock	04/09/98		10,000
8	Equity in Earnings			-594,291
9	Sub - TOTAL			-584,291
10				
11	SunWay 1, LLC			
12	Paid in Capital	5/29/08		124,873
13	Equity in Earnings			-109,884
14	Sub - TOTAL			14,989
15				
16	SunWay 2, LLC			
17	Paid in Capital	9/16/08		525,014
18	Equity in Earnings			-215,479
19	Sub - TOTAL			309,535
20				
21				
22				
23				
24				
25				
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41				
42	Total Cost of Account 123.1 $ -298,974		TOTAL	-201,554

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		1,000		2
-11,337		45,876		3
-11,337		46,876		4
				5
				6
		10,000		7
333,070	-450,000	-711,221		8
333,070	-450,000	-701,221		9
				10
				11
	31,400	156,273		12
-90		-109,974		13
-90	31,400	46,299		14
				15
				16
		525,014		17
-463		-215,942		18
-463		309,072		19
				20
				21
				22
				23
				24
				25
				26
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				41
321,180	-418,600	-298,974		42

Schedule Page: 224 Line No.: 8 Column: f

Consists of one $450,000 dividend paid to PGE by Salmon Springs Hospitality Group to reduce the intercompany receivable balance.

Schedule Page: 224 Line No.: 12 Column: f

Consists of PGE's capital contribution to SunWay 1, LLC in 2009.

Schedule Page: 224 Line No.: 12 Column: g

Represents PGE's share of SunWay 1, LLC, a variable interest entity jointly owned by PGE (0.01% interest) and U.S. bank (99.99% interest). SunWay 1, LLC was formed for the sole purpose of (1) designing, developing, constructing, owning, maintaining, operating and financing a photovoltaic solar power facility located at the intersection of I-5 North and I-205 South in Tualatin, Oregon, which is owned by the Oregon Department of Transportation, (2)selling the energy generated by the facility, and (3) licensing the site.

SunWay 1, LLC statistics at 12/31/2009 (100%)

In-service Production cost: $1,071,491
Total installed capacity: 140 kilowatts
Operations and Maintenance for 2009: $70,807

Schedule Page: 224 Line No.: 19 Column: g

Represents PGE's share of SunWay 2, LLC, a variable interest entity jointly owned by PGE (0.01% interest) and U.S. bank (99.99% interest). SunWay 2, LLC was formed for the sole purpose of (1) designing, developing, constructing, owning, maintaining, operating and financing three photovoltaic solar power facilities located on the rooftops of three different buildings in Portland, Oregon, which are owned by ProLogis (a Maryland real estate investment trust), and (2) selling the energy generated by the facilities.

SunWay 2, LLC statistics at 12/31/2009 (100%)

In-service Production cost: $5,725,626
Total installed capacity: 806 kilowatts
Operations and Maintenance for 2009: $419,896

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	34,424,362	23,897,315	
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	12,984,914	12,986,346	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	18,735,162	17,046,858	
8	Transmission Plant (Estimated)	34,603	6,905	
9	Distribution Plant (Estimated)	1,459,720	1,272,332	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	45,033	120,642	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	33,259,432	31,433,083	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	23,250	11,357	
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	3,031,841	3,051,673	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	70,738,885	58,393,428	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2010 No. (d)	2010 Amt. (e)
1	Balance-Beginning of Year	26,986.00	360,000	10,031.00	
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	7,980.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	19,006.00	360,000	10,031.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	1,153.08		144.12	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	144.78			
40	Balance-End of Year	1,008.30		144.12	
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.

2011		2012		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
10,029.00		10,032.00		190,585.00		247,663.00	360,000	1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						7,980.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
10,029.00		10,032.00		190,585.00		239,683.00	360,000	29
								30
								31
								32
								33
								34
								35
144.12		144.12		5,054.76		6,640.20		36
								37
								38
				144.78		289.56		39
144.12		144.12		4,909.98		6,350.64		40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22	Abandoned Trojan Nuclear Plant					
23	Decommissioning Costs;	307,914,940	4,646,000	407	4,646,000	
24	PGE has the authority to continue					
25	the recovery of the expense in					
26	rates, until decommissioning is					
27	complete, as authorized by OPUC					
28	(Order #07-015, dtd 1/12/2007)					
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	307,914,940	4,646,000		4,646,000	

Schedule Page: 230 Line No.: 23 Column: f

Decommissioning amounts collected from customers are in advance of expenditures on a present value basis. Amount is recorded in FERC 254.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Powerex	377	561.6	377	456
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Beaver 100MW System Integration	327	561.7	327	456
23	Beaver 200MW System Integration	875	561.7	875	456
24	Southern Crossing - Boardman Syst	2,806	561.7	2,806	456
25	CCCT at Boardman	20,912	561.7	20,912	456
26	Warm Springs Re-estimate	1,878	561.7	1,878	456
27	Beaver Network Integration	15,501	561.7	15,501	456
28	Boardman Plant-Network Integration	83	561.7	83	456
29	Beaver 100MW Peaker	8,151	561.7	8,151	456
30	Beaver 200MW Peaker	9,696	561.7	9,696	456
31	Molalla 100MW Peaker	2,258	561.7	2,258	456
32	Molalla 200MW Peaker	4,479	561.7	4,479	456
33	Martinsdale Wind Project	6,422	561.7	6,422	456
34	Boardman Feasibility Study	25,125	561.7	25,125	456
35	Coyote Springs Facility	16,395	561.7	16,395	456
36	Wind Facility Study	7,029	561.7	7,029	456
37	Beaver 100MW Facilities Study	1,961	561.7	1,961	456
38	Beaver 200MW Facilities Study	2,610	561.7	2,610	456
39	Maupin Interconnection Study	8,437	561.7	8,437	456
40	Warm Springs II	2,009	561.7	2,009	456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Martinsdale Wind System Integratn	238	561.7	238	456
23	Rock Creek Large Gen. Interconnect	13,872	561.7	13,872	456
24	Coyote Springs Re-Study	1,011	561.7	1,011	456
25	Boardman Re-Study	1,011	561.7	1,011	456
26	Coyote Springs System Impact Study	85	561.7	85	456
27	Warm Springs Facilities Study	1,661	561.7	1,661	456
28	Other	4,434	561.7	4,432	456
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231.1 Line No.: 28 Column: b

Represents various minor study costs charged to FERC 561.7 but not assigned to specific studies.

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Colstrip Common Facilities (28 year amort.	2,684,507		407.3	322,140	2,362,367
2	ending 2017, FERC OCA-AD					
3	letter dtd 5/23/1989)					
4						
5	Pelton Round Butte Transition Costs	468,198	20,388			488,586
6	(per OPUC Order No. 00-459 dtd 8/22/2000)					
7						
8	Category A Advertising Deferral (Year 2)	176,052	7,666			183,718
9	(per OPUC Order No. 03-601 dtd 10/09/2003)					
10						
11	Category A Advertising Deferral (Year 3)	163,522	7,121			170,643
12	(per OPUC Order No. 04-562 dtd 9/28/2004)					
13						
14	Intervenor Funding (original deferral per OPUC	496,134	402,437	407.3	215,772	682,799
15	Order No. 03-388 dtd 7/02/2003; current year					
16	reauthorization approved through OPUC					
17	Order No. 09-12 dtd 1/20/2009)					
18						
19	FERC Settlement	17,872	778			18,650
20	(Docket No. EL01-114 et al., dtd 11/10/2003)					
21						
22	Beaver Unit 8 Deferral	2,422,638	62,045	403	2,299,983	184,700
23	(per OPUC No. 04-740 dtd 12/15/2004;					
24	amortization period 1/01/2005 - 12/31/2009)					
25						
26	Tax Benefits Related to Book/Tax Bases Differences	65,214,139	6,684,750	282	4,652,398	67,246,491
27	Previously Flowed to Customers	40,430,238	4,220,023	283	3,763,612	40,886,649
28	(Amort. period is based on the lives of the	104,786	3,262	190	1,485	106,563
29	properties, approximately 25 years.)					
30						
31	Grid West Loans	1,570,038	135,186			1,705,224
32	(per OPUC Order No. 06-483 dtd 8/22/2006)					
33						
34	Senate Bill 408 Deferral - YR 2007	16,904,645	594,770	449.1	10,210,797	7,288,618
35	(per OPUC Order No. 07-401 dtd 9/18/2007,					
36	amortization period: 6/1/2009 - 7/31/2010)					
37						
38	Pension Funding	204,310,529		219	34,537,629	169,772,900
39	(per SFAS No. 158 adopted 12/31/2006)					
40						
41	Postretirement Funding	28,077,459		219	2,083,730	25,993,729
42	(per SFAS No. 158 adopted 12/31/2006)					
43						
44	TOTAL	814,751,272	163,155,255		322,907,448	654,999,079

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	FAS 106 Costs Deferral	2,967,832	257,500	926	3,225,332	
2						
3	Boardman Power Cost Deferral	34,154,669	2,940,845	426.5	18,547,757	18,547,757
4	(deferred per OPUC Order No. 07-049					
5	dtd 2/12/2007; recovery per OPUC Order					
6	No. 10-051 dtd 2/11/2010)					
7						
8	CIST/IT Deferral	77,989	3,396			81,385
9	(per OPUC Order No. 01-777 dtd 8/31/2001)					
10						
11	Price Risk Management	387,059,841	36,272,947	various	180,398,164	242,934,624
12						
13	Deferred Broker Settlement	18,657,182	88,393,829	555	57,547,475	49,503,536
14						
15	Tojan Refund Deferral - Incremental Costs		2,310,429			2,310,429
16	(per OPUC Order No. 09-133 dtd 4/14/2009)					
17						
18	Senate Bill 408 Deferral Local - 2006	160,330	1,984	449.1	162,314	
19	(per Advice No. 08-204 dtd 4/11/2008)					
20						
21	Drect Access Open Enrollment Deferral - 2008	3,119,679	119,166	447	2,769,341	469,504
22	(per OPUC Order No. 08-153 dtd 3/4/2008					
23	amortization period: 1/1/2009 - 12/31/2009)					
24						
25	Direct Access Open Enrollment Deferral - 2009		892,391			892,391
26	(per OPUC Order No. 08-153 dtd 3/4/2008)					
27						
28	Independent Evaluator Deferral	213,681	49,837			263,518
29	(per OPUC Order No. 08-010 dtd 1/14/2008)					
30						
31	Smart Meter Project Office Costs	1,087,708	93,656			1,181,364
32	(per OPUC Order No. 08-209 dtd 4/11/2008)					
33						
34	Schedule 110 EE - Asset Bal. Acct	11,604	483,393	407.3	451,153	43,844
35	(per Advice No. 07-25 dtd 5/20/2008)					
36						
37	Smart Meter Severance Deferral	2,000,000		930.2	165,000	1,835,000
38	(amortization period: 1/1/2009 - 12/31/2010)					
39						
40	WECO Deferral	2,200,000	18,827	501	868,874	1,349,953
41	(per Advice No. 08-16 dtd 7/24/2009					
42	amortization period: 8/1/2009 - 7/31/2010)					
43						
44	TOTAL	814,751,272	163,155,255		322,907,448	654,999,079

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Biglow Canyon Phase 2 Deferral		10,629,811			10,629,811
2	(per OPUC Order No. 09-398 dtd 10/05/2009					
3	amortization period: 1/1/2010 - 12/31/2010)					
4						
5	SunWay Deferral		92,838			92,838
6	(per OPUC Order No. 09-398 dtd 10/05/2009					
7	amortization period: 1/1/2010 - 12/31/2010)					
8						
9	Residential Critical Peak Pricing Pilot		8,703			8,703
10	(per Advice No. 09-05 dtd 9/23/2009)					
11						
12	Generation Plant Maintenance Deferral		6,844,920	553	684,492	6,160,428
13	(per OPUC Order No. 08-601 dtd 12/29/2008					
14	amortization period: 1/1/2009 - 12/31/2018)					
15						
16	Small Nonresidential Sch 123 SNA Deferral		1,497,783			1,497,783
17	(per OPUC Order No. 09-162 dtd 5/6/2009)					
18						
19	Stable Rate Revenue Balancing Acct		104,574			104,574
20	(per Advice No. 06-13 dtd 6/22/2006)					
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	814,751,272	163,155,255		322,907,448	654,999,079

Schedule Page: 232.1 Line No.: 3 Column: f

In the fourth quarter of 2009, the Boardman Power Cost Deferral was reduced by $18.5 million pursuant to the OPUC Order No. 10-051 entered February 11, 2010 which allowed recovery of 50% of PGE's originally requested deferral plus accrued interest. Pursuant to the order, collection of the remaining balance will be offset in early 2010 with certain credits currently owed to customers related to accrued savings on decommissioning activities at PGE's closed Trojan Nuclear Plant.

Schedule Page: 232.1 Line No.: 11 Column: d

Amounts charged to Accounts 555, 547, and 219.

Schedule Page: 232.1 Line No.: 15 Column: f

Balance represents incremental costs incurred to administer the Trojan Refund which was mandated per OPUC Order No. 08-487.

Schedule Page: 232.2 Line No.: 1 Column: f

On April 1, 2009, PGE submitted to the OPUC its initial filing under the Renewable Resources Adjustment Clause for recovery of its investment in the Biglow Canyon Wind Farm Phase II (PGE Advice No. 09-06). The balance of the deferral represents the incremental revenue required to recover costs related to the initial investments which went into service during 2009. This deferral was approved for recovery in OPUC Order No. 09-398, dated October 5, 2009, and will be amortized over 12 months beginning 01/01/2010 (per PGE’s approved Tariff Schedule 122).

Schedule Page: 232.2 Line No.: 5 Column: f

On April 1, 2009 PGE submitted to the OPUC its inital filing under the Renewable Resources Adjustment Clause for recovery of its investment in the SunWay solar projects (PGE Advice No. 09-16). The balance of the deferral represents the incremental revenue required to recover costs related to the initial investments from the period of 12/03/2008 (the date of the original deferral application) to 12/31/2009. This deferral was approved for recovery in OPUC Order No. 09-398, dated October 5, 2009, and will be amortized over 12 months beginning 01/01/2010 (per PGE’s approved Tariff Schedule 122).

Schedule Page: 232.2 Line No.: 9 Column: f

Balance represents Critical Peak Pricing pilot which is a demand response option for eligible residential customers. As outlined in Schedule 12, Advice No. 09-05 dated August 27, 2009, Critical Peak Pricing provides customers a price incentive to curtail peak loads during Critical Peak hours up to ten days for each six month season.

Schedule Page: 232.2 Line No.: 12 Column: f

Balance represents a deferral for future recovery of higher than normal maintenance costs for Boardman, Beaver, and Colstrip Unit #4 as approved in the 2009 General Rate Case. The additional costs were estimated to be $6,844,920. The deferral amount was determined by a comparison of the Test Year 2009 O&M expenses, as measured by the sum of preventative and corrective maintenance expenses, with the 2003-2008 averages of the same expenses. The unamortized deferred balance is addded to Rate Base; accordingly, no interest is accrued on this deferral.

Schedule Page: 232.2 Line No.: 16 Column: f

Balance represents amounts deferred for small nonresidential customers related to Schedule 123 Sales Normalization Adjustment, which captures the difference between actual and projected weather adjusted cycle usage per customer.

Schedule Page: 232.2 Line No.: 19 Column: f

Balance represents the difference between net Schedule 9 (Stable Rate Pilot) revenues and revenues that would otherwise be billed if participating customers were served under Schedule 7 (Residential Service) or Schedule 32 (Small Nonresidential Standard Service). Any balance in the Stable Rate Balancing Account will earn interest at PGE's approved rate of return and will be collected from or returned to Schedule 7 and Schedule 32 customers in a manner approved by the OPUC.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Misc. Undistributed Charges					
2	(4 items as of 12/31/2009)	33,716	49,093	Various	54,227	28,582
3						
4	Net Trust Contributions	1	95,225,259	Various	95,225,256	4
5						
6	Pebble Springs AFDC - amort.					
7	over service lives of related					
8	property	327,762		425	36,227	291,535
9						
10	Tax Credit Sale - amort. over					
11	service lives of related					
12	property	7,334		421	2,580	4,754
13						
14	NWNG Capital Contribution -					
15	amort. over 15 yrs ended 2010	366,654		547	200,004	166,650
16						
17	Deferred Wheeling Costs -					
18	amort. over 25 yrs through 2012	735,321		565	196,416	538,905
19						
20	Deferred Rent - WTC Tenant					
21	amort. over 10 yrs through 2013	148,191		418	50,460	97,731
22						
23	Deferred Revolving Credit					
24	Agreement Fees	287,899	1,800,119	431	273,695	1,814,323
25						
26	Dispatchable Generation					
27	various amort. periods beg in					
28	2000 and extending thru 2017	3,811,250	1,533,579	903	685,994	4,658,835
29						
30	Potential Sale of Supply					
31	Portfolio	154,719	3,102	426.5	156,287	1,534
32						
33	LID Receivable from WTC Tenants					
34	amort over 20 yrs through 2030		119,785			119,785
35						
36	Colstrip Operations		939,621	Various	905,896	33,725
37						
38	Colstrip - Lime Contract					
39	amort. over 4 yrs. 2011 - 2014		2,170,322			2,170,322
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	395,783				268,912
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	6,268,630				10,195,597

Schedule Page: 233   Line No.: 39   Column: f

The lime contract for the Colstrip plant ends in 2010 and in order to ensure a long term supply of lime to the plant, they entered into an agreement where funds were paid which will be used to build a new kiln to make the lime and in return, a new contract was entered into for lime purchases starting in 2011. These funds will be applied to those future purchases and amortized from 2011 to 2014.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Depreciation and Amortization	19,148,253	35,010,276
3	Regulatory Liabilities	58,215,257	35,537,010
4	Employee Benefits	101,694,457	93,631,476
5	Price Risk Management	164,199,954	98,199,241
6	Asset Retirement Obligation	19,445,966	11,110,208
7	Other	22,098,011	21,534,956
8	TOTAL Electric (Enter Total of lines 2 thru 7)	384,801,898	295,023,167
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	9,132,209	9,527,576
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	393,934,107	304,550,743

Notes

	Balance at Beginning Of Year	Balance at End Of Year
Line 7 - Other:		
Bad Debt Expense	2,204,108	2,189,340
Nuclear Decommissioning Trust	9,304,929	8,989,981
Deferred Tax Credits	5,346,628	5,011,324
Miscellaneous Other	5,242,346	5,344,311
Total Line 7 - Other	22,098,011	21,534,956
Line 17 - Other - NonUtility		
Depreciation & Amortization	5,298,166	5,780,094
Software Costs	820,307	820,308
Miscellaneous	3,013,736	2,927,174
Total Line 17 - Other - NonUtility	9,132,209	9,527,576

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201:			
2	Common Stock	160,000,000		
3				
4	Total_Com	160,000,000		
5				
6	Account 204:			
7	No Par Value Cumulative Preferred	30,000,000		
8				
9	Total_pre	30,000,000		
10				
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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
75,210,580	821,983,367					2
						3
75,210,580	821,983,367					4
						5
						6
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Schedule Page: 250 Line No.: 2 Column: b

In Q1 2009, PGE's Board of Directors approved an increase to the number of shares of common stock that the company is authorized to issue from 80 million to 160 million.

Schedule Page: 250 Line No.: 2 Column: e

In March 2009, PGE issued 12,477,500 shares of common stock with net proceeds of $170 million.

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	
2	Parent equity contributions from employee stock purchase and	
3	compensation and associated income tax benefits	4,804,482
4	SUBTOTAL ACCOUNT 208	4,804,482
5		
6	Account 209	
7	Reduction in par or stated value of Common Stock	1,556,498
8	SUBTOTAL Account 209	1,556,498
9		
10	Account 210	
11	Capital Restructuring Costs	50,570
12	SUBTOTAL Account 210	50,570
13		
14	Account 211	
15	Miscellaneous paid in capital	640,957
16	Amortization of capital stock expense	-646,425
17	Tax benefits related to stock compensation plans	36,776
18	Reacquired common stock	-68,327
19	Enron assumption of PGE tax liabilities on Non-Qualified Plan transfer	610,028
20	Oregon tax credit related to PGE's separation from Enron	8,317,515
21	SUBTOTAL Account 211	8,890,524
22		
23		
24		
25		
26		
27		
28		
29		
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31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	15,302,074

Schedule Page: 253 Line No.: 19 Column: b

PGE generated approximately $13 million of Oregon tax credits that, due to taxable income limitations, were not utilized by Enron prior to the separation of the two companies on April 3, 2006. Prior to 2006, pursuant to a tax sharing agreement, PGE utilized these tax credits to reduce its tax payment obligations to Enron. Uncertainties existed with respect to the timing and ability by Enron to utilize the credits. To the extent that Enron was unable to utilize these credits on its tax returns, PGE utilized a portion of the tax credits to offset quarterly income tax payments due to the state of Oregon during periods subsequent to the separation, with no effect on income. In 2008, PGE made an assessment that it is remote that Enron will be able to utilize these tax credits. Therefore, the realization of such tax credits by PGE is reflected as an adjustment to equity, net of related federal tax effect, during the year ended December 31, 2008.

Schedule Page: 253 Line No.: 20 Column: b

PGE generated approximately $13 million of Oregon tax credits that, due to taxable income limitations, were not utilized by Enron prior to the separation of the two companies on April 3, 2006. Prior to 2006, pursuant to a tax sharing agreement, PGE utilized these tax credits to reduce its tax payment obligations to Enron; however, Enron was unable to utilize these credits on its tax returns. PGE then utilized a portion of the tax credits to offset quarterly income tax payments due to the State of Oregon during periods subsequent to the separation, with no effect on income. In 2008 and 2009, the realization of such tax credits by PGE was reflected as an adjustment to equity, net of related federal tax effect.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	7,729,446
2		
3		
4	No Par Cumulative Preferred Stock - 7.75% Series	305,275
5		
6		
7		
8		
9		
10		
11		
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16		
17		
18		
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20		
21		
22	TOTAL	8,034,721

Schedule Page: 254 Line No.: 1 Column: b

In connection with the March 2009 common stock issuance, common stock expense increased $6,454,538 from 2008.

Schedule Page: 254 Line No.: 1 Column: b

Footnote Linked. See note on 254, Row: 1, col/item:

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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 - Bonds:		
2	First Mortgage Bonds -		
3	5.6675% Series due 2012	100,000,000	12,248,703
4	9.31% Medium-Term Note Series Due 8/11/2021	20,000,000	176,577
5	5.625% Series VI Due 8/1/2013	50,000,000	406,662
6			325,000 D
7	6.75% Series VI Due 8/1/2023	50,000,000	519,234
8			437,500 D
9	6.875% Series VI Due 8/1/2033	50,000,000	519,257
10			437,500 D
11	6.26% Series Due 5/1/2031	100,000,000	723,856
12	6.31% Series Due 5/1/2036	175,000,000	1,270,565
13	5.80% Series Due 6/1/2039	170,000,000	1,460,968
14	5.81% Series Due 10/1/2037	130,000,000	1,109,574
15			517,518 D
16	5.80% Series Due 03/01/2018	75,000,000	282,501
17	4.45% Series Due 04/1/2013	50,000,000	340,444
18			625,100 D
19	6.50% Series Due 1/15/2014 - Order No. 08-106 01/28/2008	63,000,000	429,463
20	6.80% Series Due 1/15/2016 - Order No. 08-106 01/28/2008	67,000,000	456,731
21	6.10% Series Due 4/15/2019 - Order No. 09-089 03/16/2009	300,000,000	2,386,224
22			222,000 D
23	5.43% Series Due 5/3/2040 - Order No. 09-245 06/22/2009	150,000,000	1,034,284
24			
25			
26	Pollution Control Bonds (Guaranteed by Company) -		
27	Port of Morrow, OR Series 1996 Due 12/1/2031 Variable Rate	5,800,000	159,350
28	Port of Morrow, OR Series 1998A Due 5/1/2033 (5.20% to 5/1/09,variable thereafter)	23,600,000	197,390
29			243,792
30	City of Forsyth, MT Series 1998A Due 5/1/2033 (5.20% to 5/1/09,variable thereafter)	97,800,000	928,277
31			1,010,292
32	Port of St. Helens, OR Series 1985A 4.80% Due 4/1/2010	20,200,000	735,003
33	TOTAL	1,894,975,785	33,328,774

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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	Port of St. Helens, OR Series 1985B 4.80% Due 6/1/2010	16,700,000	570,294
2	City of Forsyth, MT Series 1998B Due 5/1/2033 (5.20% to 5/1/09,variable thereafter)	21,000,000	212,637
3			216,931
4	Port of St. Helens, OR Series 1990A 5.25% due 8/1/2014	9,600,000	386,344
5			
6	SUBTOTAL ACCOUNT 221	1,744,700,000	30,589,971
7			
8			
9			
10	ACCOUNT 224 - OTHER LONG TERM DEBT		
11			
12	Real Estate Contract Notes	156,000	
13	7.875% Notes due 3/15/2010	150,000,000	1,472,803
14			1,266,000 D
15	City of Portland Improvement District Loan	119,785	
16	SUBTOTAL ACCOUNT 224	150,275,785	2,738,803
17			
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27			
28			
29			
30			
31			
32			
33	TOTAL	1,894,975,785	33,328,774

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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
						2
10/28/2002	10/25/2012	10/28/2002	10/25/2012	100,000,000	5,667,504	3
08/12/1991	08/11/2021	08/12/1991	08/11/2021	20,000,000	1,862,004	4
08/01/2003	08/01/2013	08/01/2003	08/01/2013	50,000,000	2,812,500	5
						6
08/01/2003	08/01/2023	08/01/2003	08/01/2023	50,000,000	3,375,000	7
						8
08/01/2003	08/01/2033	08/01/2003	08/01/2033	50,000,000	3,437,496	9
						10
05/26/2006	05/01/2031	05/26/2006	05/01/2031	100,000,000	6,260,004	11
05/26/2006	05/01/2036	05/26/2006	05/01/2036	175,000,000	11,042,496	12
05/16/2007	06/01/2039	05/16/2007	06/01/2039	170,000,000	9,860,004	13
09/19/2007	10/01/2037	09/19/2007	10/01/2037	130,000,000	7,552,992	14
						15
12/12/2007	03/01/2018	12/12/2007	03/01/2018	75,000,000	4,350,000	16
04/15/2008	04/01/2013	04/15/2008	04/01/2013	50,000,000	2,225,004	17
						18
01/15/2009	01/15/2014	01/15/2009	01/15/2014	63,000,000	3,924,375	19
01/15/2009	01/15/2016	01/15/2009	01/15/2016	67,000,000	4,366,170	20
04/16/2009	04/15/2019	04/16/2009	04/15/2019	300,000,000	12,962,500	21
						22
11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	1,312,250	23
						24
						25
						26
12/23/1996	12/01/2031	12/23/1996	12/01/2031		30,427	27
5/28/1998	05/01/2033	05/28/1998	05/01/2033		409,068	28
		05/01/2003	05/01/2009			29
05/28/1998	5/01/2033	05/28/1998	05/01/2033		1,695,200	30
		05/01/2003	05/01/2009			31
04/01/1985	4/1/2010	04/01/1985	04/01/2010	20,200,000	969,600	32
				1,745,883,985	97,557,599	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.
06/01/1985	6/1/2010	06/01/1985	06/01/2010	16,700,000	801,600	1
05/28/1998	5/1/2033	05/28/1998	05/01/2033		381,500	2
		05/01/2003	05/01/2009			3
08/08/1990	8/1/2014	08/08/1990	08/01/2014	9,600,000	504,000	4
						5
				1,596,500,000	85,801,694	6
						7
						8
						9
						10
						11
05/28/2000	6/28/2010			14,200	2,469	12
03/13/2000	3/15/2010	03/13/2000	03/15/2010	149,250,000	11,753,436	13
						14
11/16/2009	11/16/2029			119,785		15
				149,383,985	11,755,905	16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				1,745,883,985	97,557,599	33

Schedule Page: 256 Line No.: 27 Column: b

The bonds were purchased during the first quarter of 2008 and may be remarketed at a later date.

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

The bonds were purchased during the second quarter of 2009 and may be remarketed at a later date.

Schedule Page: 256 Line No.: 30 Column: h

The bonds were purchased during the second quarter of 2009 and may be remarketed at a later date.

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

The bonds were purchased during the second quarter of 2009 and may be remarketed at a later date.

Schedule Page: 256.1 Line No.: 15 Column: b

The loan represents liability to the City of Portland mall revitalization local project improvement district. PGE will make payments for 20 years semi-annually at a 6.75% interest rate.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	95,365,873
2		
3		
4	Taxable Income Not Reported on Books	
5	SO2 Emissions Credits	11,091
6	NQ Nuclear Decommissioning Trust Investment Income	94,164
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Depreciation, Depletion & Amortization	230,618,704
11	Price Risk Management & Mark-to-Market	147,339,980
12	Regulatory Debits	41,743,890
13	Total Other (See Footnote)	56,736,655
14	Income Recorded on Books Not Included in Return	
15	Price Risk Management & Mark-to-Market	-175,492,165
16	Regulatory Credits	-21,808,285
17	Miscellaneous	-10,834,208
18		
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	-415,374,428
21	Regulatory Deferrals	-63,344,998
22	State & Local Tax Deduction	335,295
23	Total Other (See Footnote)	-8,299,530
24		
25		
26		
27	Federal Tax Net Income	-122,907,962
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @ 35%	-43,017,787
30	Federal Energy Tax Credit	-10,475,766
31	2006b & 2007 Amended Returns	-808,017
32	2008 Return to Accrual Adjustment	8,655,107
33	2008 Federal Cap Loss Carryback	-254,350
34	Total Federal Income Tax - PGE	-45,900,813
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 13 Column: b

Employee Benefits	$12,531,677
FAS 158 Adjustments	2,047,928
Miscellaneous	3,816,342
Travel & Entertainment	567,000
Bad Debts	823,863
Political Activity	960,547
Federal Provision	15,488,190
State Provision	20,501,108
Total Other	$56,736,655

Schedule Page: 261 Line No.: 23 Column: b

Miscellaneous	$(2,490,149)
Qualified NDT	(881,290)
Employee Benefits	(4,696,332)
Bad Debts	(227,603)
Corporate Memberships & Industry Association Dues	(4,156)
Total Other	$(8,299,530)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	FERC Resale/Coord	106,074		491,316	491,316	
3	Income Tax		7,699,576	-45,900,813	1,467,547	149,793
4	Foreign Insurance Excise Tax					
5	FICA (Employer Share)	1,650,023		16,856,994	17,683,339	
6	Unemployment	81,539		127,026	170,191	
7	Power License	482,304		2,680,153	1,388,881	
8	Superfund Tax					
9	SUBTOTAL Federal	2,319,940	7,699,576	-25,745,324	21,201,274	149,793
10	State of Montana:					
11	Income Tax		90,363	-106,240		
12	Elec. Energy Producers Tax	220,500		643,308	630,609	
13	Property Taxes	2,184,538		3,990,691	4,184,848	
14	SUBTOTAL Montana	2,405,038	90,363	4,527,759	4,815,457	
15	State of Oregon:					
16	Corp Excise Tax	35,763		-35,804	99,960	43,953
17	Property Taxes		15,445,716	32,707,435	33,191,971	
18	City Taxes and Licenses	3,154,256	1,150	37,498,684	37,178,056	
19	Public Utility Comm Fees			4,815,771	4,815,771	
20	Department of Energy		526,726	526,726		
21	Department of Enviro Quality	478,090		397,384	404,644	
22	Unemployment	133,796		966,494	994,251	
23	Water Power Fee		215,440	215,437	217,685	
24	Transportation Tax	214,811		1,198,103	1,266,020	
25	Workers Comp Assessment	44,083		172,675	171,302	
26	County & City Income Tax		156,274	-194,052	60,030	21,077
27	SUBTOTAL Oregon	4,060,799	16,345,306	78,268,853	78,399,690	65,030
28	State of Washington:					
29	Property Taxes	42,000		42,497	46,097	
30	Sales Tax	1,329			1,331	
31	SUBTOTAL Washington	43,329		42,497	47,428	
32	State of Wyoming:					
33	Sales Tax					
34	SUBTOTAL Wyoming					
35	State of California:					
36	Corporate franchise tax			800	800	
37	SUBTOTAL California			800	800	
38	Canada:					
39	Goods & Services Tax					
40	SUBTOTAL Canada					
41	TOTAL	8,829,106	24,135,245	57,094,585	104,464,649	214,823

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
106,074					491,316	2
	54,918,143	-46,503,818			603,005	3
		4,500			-4,500	4
823,680		9,674,074			7,182,921	5
38,372		72,789			54,237	6
1,773,577					2,680,153	7
						8
2,741,703	54,918,143	-36,752,455			11,007,132	9
						10
	196,603	-108,405			2,165	11
233,200		375,638			267,670	12
1,990,382		3,413,229			577,462	13
2,223,582	196,603	3,680,462			847,297	14
						15
	56,048	-160,502			124,698	16
	15,930,252	30,255,206			2,452,229	17
3,473,731		37,527,143			-28,459	18
					4,815,771	19
		1,031,704			-504,977	20
470,830					397,384	21
106,039		553,825			412,669	22
	217,688				215,437	23
146,892		1,198,103				24
45,457		98,947			73,728	25
	389,279	-204,003			9,951	26
4,242,949	16,593,267	70,300,423			7,968,431	27
						28
38,400		42,497				29
						30
38,400		42,497				31
						32
						33
						34
						35
					800	36
					800	37
						38
						39
						40
9,246,634	71,708,013	37,270,927			19,823,660	41

Schedule Page: 262 Line No.: 3 Column: f

Intercompany tax consolidation with subsidiaries $ 179,346
Federal liability for Oregon credits received from deconsolidation $ (41,710)
Transfer to APIC for restricted stock unit vesting $ 12,157

Schedule Page: 262 Line No.: 16 Column: f

Intercompany tax consolidation with subsidiaries $ 43,953

Schedule Page: 262 Line No.: 26 Column: f

Intercompany tax consolidation with subsidiaries $ 21,077

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	1,456,233			411.4	1,456,233	
6	10%	480,478			420	418,483	
7							
8	TOTAL	1,936,711				1,874,716	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
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47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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
61,995	see note		6
			7
61,995			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
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			38
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			40
			41
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			46
			47
			48

Schedule Page: 266 Line No.: 6 Column: i

Investment tax credit amortized to income over period ending in 2011.

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Miscellaneous credits (2 items)	89,461	Various	26,757	45	62,749
2						
3	Accelerated cost recovery system					
4	tax benefit sale - amort. over					
5	service lives of related					
6	property	335,097	421	38,808		296,289
7						
8	Reserve for Boardman Interest				1,229,780	1,229,780
9						
10	Deferred Liability for Transferred					
11	Non-Qualified Plan Benefits	1,097,164	421	90,315		1,006,849
12						
13	Deferred premiums on power					
14	options sold		555	2,847,800	2,847,800	
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
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33						
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35						
36						
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38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	1,521,722		3,003,680	4,077,625	2,595,667

Schedule Page: 269   Line No.: 8   Column: f

This amount represents the difference between PGE's approved Cost of Capital rate applied to the Boardman Power Cost Deferral regulatory asset (FERC 182.3) and PGE's approved Cost of Debt. Generally Accepted Accounting Principles (ASC 980-340) allows "capitalization of an incurred cost that would otherwise be charged to expense"; therefore, since the return on the equity component of the Cost of Capital rate is not a cost that would otherwise be charged to expense, it should not be capitalized. FERC account 182.3 (Other Regulatory Assets) requires the capitalization of costs resulting from actions of regulators, and since the Oregon Public Utility Commission allows recovery at PGE's Cost of Capital rate, this is the amount that accrued to FERC 182.3, with an offset to FERC 253 - Other Deferred Credits.

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

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

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

NOTES

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
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							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	335,450,266	143,792,112	80,948,813
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	335,450,266	143,792,112	80,948,813
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	335,450,266	143,792,112	80,948,813
10	Classification of TOTAL			
11	Federal Income Tax	282,519,568	121,101,717	68,175,090
12	State Income Tax	47,254,879	20,217,171	11,381,403
13	Local Income Tax	5,675,819	2,473,224	1,392,320

NOTES

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
	1,654,249			190, 182.3	8,320,997	404,960,313	2
							3
							4
	1,654,249				8,320,997	404,960,313	5
							6
							7
							8
	1,654,249				8,320,997	404,960,313	9
							10
	1,393,209				7,007,944	341,060,930	11
	232,587				1,169,932	57,027,992	12
	28,453				143,121	6,871,391	13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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	Depreciation and Amortization	38,506,446		
4	Price Risk Management	182,716,488	2,666,022	57,458,310
5	Regulatory Contingencies	21,370,578	15,879,062	21,517,125
6	Asset Retirement Obligation	10,060,059	10,805,311	9,755,161
7	Other	93,616,673	638,794	454,303
8				
9	TOTAL Electric (Total of lines 3 thru 8)	346,270,244	29,989,189	89,184,899
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	38,289		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	346,308,533	29,989,189	89,184,899
20	Classification of TOTAL			
21	Federal Income Tax	291,664,510	25,257,195	75,112,414
22	State Income Tax	48,784,482	4,224,577	12,563,477
23	Local Income Tax	5,859,541	507,417	1,509,008

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2	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
							2
				182.3	1,607,892	40,114,338	3
		190	279,523			127,644,677	4
1,342,005	2,732,037			190	20,129	14,362,612	5
			1			11,110,208	6
		219	14,626,363	219	282,287	79,457,088	7
							8
1,342,005	2,732,037		14,905,887		1,910,308	272,688,923	9
							10
							11
							12
							13
							14
							15
							16
							17
8,770,968	6,703,617					2,105,640	18
10,112,973	9,435,654		14,905,887		1,910,308	274,794,563	19
							20
8,517,246	7,946,802		12,553,868		1,608,861	231,434,728	21
1,424,615	1,329,201		2,099,849		269,163	38,710,310	22
171,112	159,651		252,170		32,284	4,649,525	23

NOTES (Continued)

Schedule Page: 276 Line No.: 5 Column: b

	Balance at Beg. of Year	Balance at End of Year
Boardman Power Cost Deferral	$ 12,264,094	$ 6,086,696
Senate Bill 1149	2,092,078	0
Miscellaneous	7,014,406	8,275,916
Total Line 5	$ 21,370,578	$14,362,612

Schedule Page: 276 Line No.: 7 Column: b

	Balance at Beg. of Year	Balance at End of Year
Employee Benefits	$83,819,581	$69,826,298
Other	9,797,092	9,630,790
Total Line 7	$93,616,673	$79,457,088

Schedule Page: 276 Line No.: 18 Column: b

	Balance at Beg. of Year	Balance at End of Year
TOLI Gain/Loss	$ (7,874)	$ 2,575,762
Other	46,163	(470,122)
Total Line 18	$ 38,289	$ 2,105,640

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Excess Deferred Taxes	8,876,731	190	298,181	165,646	8,744,196
2		8,055,566	283	331,053	255,170	7,979,683
3						
4	Deferred Taxes on Investment Tax Credits	755,319	190	731,140		24,179
5		482,907	283	467,450		15,457
6						
7	Surplus CAA Allowances	655,449	232	5,186	16,275	666,538
8	(per Order No. 552 dtd 3/31/1993)					
9						
10	Gain on Asset Sales	5,218,228	407.4	3,269,710	230,215	2,178,733
11	(per OPUC Order No. 01-777 dtd 8/31/2001)					
12						
13	Interest on Portland Energy Solutions Note	204,315			17,591	221,906
14	(per OPUC Order No. 02-280 dtd 4/19/2002)					
15						
16	Asset Retirement Obligations - Balancing Account	26,189,189			3,628,283	29,817,472
17						
18	Williams Settlement	37,135			1,617	38,752
19	(per OPUC Order No. 04-286 dtd 4/19/2004)					
20						
21	Power Cost Adjustment (Oct 2001 - Dec 2002)	1,732,548			75,444	1,807,992
22	(per OPUC Order No. 04-293 dtd 5/24/2004)					
23						
24	Coyote Springs Major Maintenance Accrual	8,232,812	407.4	4,467,687	2,044,272	5,809,397
25	(per OPUC Order No. 01-777 dtd 8/31/2001;					
26	collection from customers through 2009)					
27						
28	ISFSI Pollution Control Tax Credit Deferral	16,713,357	407.3	1,409,601	1,817,397	17,121,153
29	(per OPUC Order No. 05-136 dtd 3/15/2005)					
30						
31	Category A Advertising Deferral (Year 1)	1,709			74	1,783
32	(per OPUC Order No. 01-777 dtd 8/31/2001)					
33						
34	Energy Efficiency Programs' Residual	137,892			6,005	143,897
35	(per Advice No. 05-19 dtd 12/20/2005)					
36						
37	Zero Interest Program Loan Repayments	595,310			158,836	754,146
38	(per Advice No. 05-19 dtd 12/20/2005)					
39						
40						
1	BPA Subscription Power - Balancing Account	10,064,187	456	53,259,875	52,690,135	9,494,447
2	(per OPUC Order No. 08-175 dtd 3/20/2008)	1,805,819			130,194	1,936,013
3						
4	Power Cost Adjustment Mechanism	18,893,367	456	18,226,822	381,172	1,047,717
41	TOTAL	124,898,690		85,343,191	66,890,563	106,446,062

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
5	(per OPUC Order No. 07-015 dtd 1/12/2007)					
6						
7	Conservation Investment Assets	77,426			3,351	80,777
8						
9	Prior Tax Benefits Recoverable	19,882				19,882
10	(per OPUC Order No. 00-601 dtd 9/29/2000)					
11						
12	Gas Transportation Cost Deferral - YR 2007	2,876,486	242	2,876,486		
13	(per OPUC Order No. 06-575 dtd 10/9/2006)					
14						
15	Old Meters - Balancing Acct	2,348,689			2,442,192	4,790,881
16	(per OPUC Order No. 08-245 dtd 5/5/2008)					
17						
18	SB1149 Residual Balance	1,298,753			103,297	1,402,050
19	(per OPUC Order No. 00-038 dtd 1/24/2000;					
20	amrt. over 5 years beg. 1/1/2004)					
21						
22	Trojan Decom Asset Balancing Acct	9,625,614			2,723,397	12,349,011
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	124,898,690		85,343,191	66,890,563	106,446,062

Schedule Page: 278 Line No.: 28 Column: d

PGE defers the tax benefits resulting from Oregon state tax credits related to the Independent Spent Fuel Storage Installation (ISFSI) at Trojan, per OPUC Order No. 05-136. At year-end 2009, PGE evaluated accrued but unused tax credits to determine if the credits could be expected to be used prior to expiration of their carry forward provisions. For ISFSI tax credits accrued in 2008, it was determined that $1.4 million are not expected to be used; accordingly, the deferred balance was reduced, with a corresponding decrease to income tax expense.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	793,811,727	757,983,657
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	607,511,065	581,232,240
5	Large (or Ind.) (See Instr. 4)	160,556,586	147,373,490
6	(444) Public Street and Highway Lighting	17,850,491	17,406,270
7	(445) Other Sales to Public Authorities	6,088	6,115
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,579,735,957	1,504,001,772
11	(447) Sales for Resale	274,168,670	531,182,238
12	TOTAL Sales of Electricity	1,853,904,627	2,035,184,010
13	(Less) (449.1) Provision for Rate Refunds	-385,092	30,173,138
14	TOTAL Revenues Net of Prov. for Refunds	1,854,289,719	2,005,010,872
15	Other Operating Revenues		
16	(450) Forfeited Discounts	785,251	800,698
17	(451) Miscellaneous Service Revenues	1,801,406	1,788,854
18	(453) Sales of Water and Water Power	44,968	-10,068
19	(454) Rent from Electric Property	6,646,519	6,118,336
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	95,993,713	60,741,182
22	(456.1) Revenues from Transmission of Electricity of Others	6,416,170	7,028,868
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	111,688,027	76,467,870
27	TOTAL Electric Operating Revenues	1,965,977,746	2,081,478,742

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
7,900,585	7,877,595	714,377	710,991	2
				3
7,043,916	7,116,096	100,973	99,814	4
2,363,991	2,472,100	271	262	5
110,646	109,931	247	247	6
74	84	1	1	7
				8
				9
17,419,212	17,575,806	815,869	811,315	10
7,553,992	8,893,586	47	53	11
24,973,204	26,469,392	815,916	811,368	12
				13
24,973,204	26,469,392	815,916	811,368	14

Line 12, column (b) includes $ -301,000 of unbilled revenues.

Line 12, column (d) includes -84,795 MWH relating to unbilled revenues

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

Includes $6,643,858 in revenue related to the delivery of 405,390 megawatt hours to customers of Electricity Service Suppliers (ESSs). Oregon's electricity restructuring law provides for a "transition adjustment" for customers that choose to purchase energy at market prices from investor-owned utilities or from an ESS. Such charges or credits reflect the above market or below market costs, respectively, for energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utility's remaining energy customers. For 2009, the "transition adjustment" credits provided to many commercial and industrial customers was less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301 Column(d).

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

Includes $931,936 in revenue related to the delivery of 614,852 megawatt hours to customers of Electricity Service Suppliers (ESSs). Oregon's electricity restructuring law provides for a "transition adjustment" for customers that choose to purchase energy at market prices from investor-owned utilities or from an ESS. Such charges or credits reflect the above market or below market costs, respectively, for energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utility's remaining energy customers. For 2008, the "transition adjustment" credits provided to many commercial and industrial customers exceeded the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301 Column (e).

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

Includes a $6,635,623 charge (reduction of revenue) related to the delivery of 1,512,307 megawatt hours to customers of Electricity Services Suppliers (ESSs). For 2009, the "transition adjustment" credits provided to many commercial and industrial customers exceeded the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301 Column (d).

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

Includes a $11,252,114 charge (reduction of revenue) related to the delivery of 1,802,464 megawatt hours to customers of ESSs. For 2008, the "transition adjustment" credits provided to many commercial and industrial customers exceeded the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301 Column (e).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Sales:					
2	7 Residential Service	7,895,484	788,817,632	711,782	11,093	0.0999
3	9 Stable Rate Pilot	27,670	2,843,599	2,595	10,663	0.1028
4	15 Outdoor Area Lighting	6,933	1,502,496			0.2167
5	Residential Unbilled Revenue	-29,502	648,000			-0.0220
6	TOTAL Account 440	7,900,585	793,811,727	714,377	11,059	0.1005
7						
8	General Comm. and Ind. Sales:					
9	9 Stable Rate Pilot	1,896	202,639	74	25,622	0.1069
10	15 Comm. Outdoor Lighting	16,668	2,768,238			0.1661
11	32 Small Nonresidential	1,497,173	147,364,811	84,610	17,695	0.0984
12	38 Optional Time of Day -	34,538	3,575,121	264	130,826	0.1035
13	Large Nonresidential					
14	47 Irrigation - Drainage - Small	20,671	2,346,584	1,867	11,072	0.1135
15	49 Irrigation - Drainage - Large	63,553	5,007,588	908	69,992	0.0788
16	83-S Large Nonresidential	4,876,414	397,171,199	12,916	377,548	0.0814
17	89-S Large Nonresidential	552,217	42,801,031	88	6,275,193	0.0775
18	483-S COS Opt-Out - Lrg. Nonresid	685	44,140	1	685,000	0.0644
19	483-S COS Opt-Out - Lrg. Nonresid		1,257	10		
20	489-S COS Opt-Out - Lrg. Nonresid	11,234	587,856	1	11,234,000	0.0523
21	489-S COS Opt-Out - Lrg. Nonresid		-66,480	4		
22	532 DAS - Small Nonresidential		16,357	10		
23	583-S DAS - Large Nonresidential		5,642,255	212		
24	589-S DAS - Large Nonresidential		723,469	8		
25	Gen Comm. & Ind. Unbilled Revenue	-31,133	-675,000			0.0217
26	TOTAL Account 442 - Small	7,043,916	607,511,065	100,973	69,760	0.0862
27						
28	Large Industrial Power Sales:					
29	75 Partial Requirements Service	179,324	11,902,011	1	179,324,000	0.0664
30	83-T Large Nonresidential					
31	83-P Large Nonresidential	293,203	22,423,044	153	1,916,359	0.0765
32	89-T Large Nonresidential	388,216	25,687,565	7	55,459,429	0.0662
33	89-P Large Nonresidential	1,527,473	107,867,589	92	16,602,967	0.0706
34	483-P COS Opt-Out - Lg. Nonresid					
35	489-T COS Opt-Out - Lg. Nonreside		-2,960,006	2		
36	489-P COS Opt-Out - Lg. Nonreside		-4,566,761	10		
37	583-T DAS - Large Nonresidential					
38	583-P DAS - Large Nonresidential		35,422	3		
39	589-P DAS - Large Nonresidential		483,722	3		
40	Large Industrial Unbilled Revenue	-24,225	-316,000			0.0130
41	TOTAL Billed	17,504,007	1,580,036,957	815,869	21,454	0.0903
42	Total Unbilled Rev.(See Instr. 6)	-84,795	-301,000	0	0	0.0035
43	TOTAL	17,419,212	1,579,735,957	815,869	21,351	0.0907

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	TOTAL Account 442 - Large	2,363,991	160,556,586	271	8,723,214	0.0679
2						
3	Various Public Street and					
4	Highway Lighting:					
5	Street Lighting	110,581	17,808,491	247	447,696	0.1610
6	Street Lighting Unbilled Rev	65	42,000			0.6462
7	TOTAL Account 444	110,646	17,850,491	247	447,960	0.1613
8						
9	Other Sales to Public Authorities					
10	Communication Devices Electr	74	6,088	1	74,000	0.0823
11	TOTAL Account 445	74	6,088	1	74,000	0.0823
12						
13						
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41	TOTAL Billed	17,504,007	1,580,036,957	815,869	21,454	0.0903
42	Total Unbilled Rev.(See Instr. 6)	-84,795	-301,000	0	0	0.0035
43	TOTAL	17,419,212	1,579,735,957	815,869	21,351	0.0907

Schedule Page: 304 Line No.: 18 Column: a

Rate Schedule 483 complete title: Large Nonresidential (<1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 18 Column: b

Customers on this rate schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. In 2009, this customer purchased its energy from PGE.

Schedule Page: 304 Line No.: 19 Column: a

Rate Schedule 483 complete title: Large Nonresidential (<1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 19 Column: b

Customers on this rate schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 20 Column: a

Rate Schedule 489 complete title: Large Nonresidential (>1,000 kW) Cost of Service Opt-out

Schedule Page: 304 Line No.: 20 Column: b

Customers on this rate schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. In 2009, this customer purchased its energy from PGE.

Schedule Page: 304 Line No.: 21 Column: a

Rate Schedule 489 complete title: Large Nonresidential (>1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 21 Column: b

Customers on this rate schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 21 Column: c

Oregon's electricity restructuring law provides all commercial and industrial customers of investor-owned utilities direct access to competing Electricity Service Suppliers (ESSs). The law provides for a "transition adjustment" for customers that choose to purchase energy at market prices from investor-owned utilities or from an ESS. Such charges or credits reflect the above market or below market costs, respectively, of energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utility's remaining energy customers. For 2009, the "transition adjustment" credits provided to customers on this schedule exceeded their charges for *delivering* the energy they purchased from an ESS. This note applies to column (c), lines 21 and 35 through 36.

Schedule Page: 304 Line No.: 22 Column: a

Rate Schedule 532 complete title: Small Nonresidential Direct Access Service.

Schedule Page: 304 Line No.: 22 Column: b

Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 23 Column: a

Rate Schedule 583 complete title: Large Nonresidential Direct Access Service.

Schedule Page: 304 Line No.: 23 Column: b

Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 24 Column: a

Rate Schedule 589 complete title: Large Nonresidential (>1,000 kW) Direct Access Service.

Schedule Page: 304 Line No.: 24 Column: b

Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 34 Column: a

Rate Schedule 483 complete title: Large Nonresidential (<1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 34 Column: b

Customers on this rate schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 35 Column: a

Rate Schedule 489 complete title: Large Nonresidential (>1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 35 Column: b

Customers on this rate schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 36 Column: a

Rate Schedule 489 complete title: Large Nonresidential (>1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 36 Column: b

Customers on this rate schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 37 Column: a

Rate Schedule 583 complete title: Large Nonresidential Direct Access Service.

Schedule Page: 304 Line No.: 37 Column: b

Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 38 Column: a

Rate Schedule 583 complete title: Large Nonresidential Direct Access Service.

Schedule Page: 304 Line No.: 38 Column: b

Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 39 Column: a

Rate Schedule 589 complete title: Large Nonresidential (>1,000 kW) Direct Access Service.

Schedule Page: 304 Line No.: 39 Column: b

Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	RQ Sales:					
2	Fale-Safe Corporation	RQ	PGE-1	75	75	75
3						
4	Avista Corp	SF	WSPP-1	NA	NA	NA
5	Barclays Bank	SF	WSPP-1	NA	NA	NA
6	BC Hydro	SF	WSPP-1	NA	NA	NA
7	Black Hills Power	SF	WSPP-1	NA	NA	NA
8	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
9	BP Energy Company	SF	WSPP-1	NA	NA	NA
10	Burbank, City of	SF	WSPP-1	NA	NA	NA
11	California Independent System Operator	SF	WSPP-1	NA	NA	NA
12	Calpine Energy Services	SF	PGE-11	NA	NA	NA
13	Cargill Alliant LLC	SF	WSPP-1	NA	NA	NA
14	Chelan County PUD No 1, Washington	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Clatskanie County PUD, Washington	SF	WSPP-1	NA	NA	NA
2	Conoco Phillips	SF	WSPP-1	NA	NA	NA
3	Constellation Energy Commodities	SF	PGE-11	NA	NA	NA
4	Credit Suisse Energy	SF	WSPP-1	NA	NA	NA
5	Douglas County PUD, No 1, Washington	SF	WSPP-1	NA	NA	NA
6	Enmax Financial Services	SF	PGE-11	NA	NA	NA
7	Epcor Energy Marketing	SF	WSPP-1	NA	NA	NA
8	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
9	Fortis Energy	SF	WSPP-1	NA	NA	NA
10	Glendale, City of	LF	PGE-78	20	20	19
11	Glendale, City of	SF	WSPP-1	NA	NA	NA
12	Grant County, PUD No 2, Washington	SF	WSPP-1	NA	NA	NA
13	Iberdrola Renewables	SF	WSPP-1	NA	NA	NA
14	Idaho Power Company	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	J. Aron Company	SF	PGE-11	NA	NA	NA
2	JP Morgan Ventures	SF	WSPP-1	NA	NA	NA
3	Load Balance Energy	OS	OATT	NA	NA	NA
4	Los Angeles Department Water Power	SF	WSPP-1	NA	NA	NA
5	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
6	Mirant Americas Energy Marketing	SF	PGE-11	NA	NA	NA
7	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
8	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
9	Northern California Power Agency	SF	WSPP-1	NA	NA	NA
10	Northpoint Energy Solutions	SF	WSPP-1	NA	NA	NA
11	Northwestern Corporation	SF	WSPP-1	NA	NA	NA
12	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
13	Pacific Gas & Electric Company	SF	WSPP-1	NA	NA	NA
14	Pacific Northwest Generating Company	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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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 Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	PacifiCorp	LU	PGE-11	NA	NA	NA
2	PacifiCorp	SF	PGE-11	NA	NA	NA
3	Powerex Corp	SF	PGE-11	NA	NA	NA
4	PPL Energy Plus	SF	PGE-11	NA	NA	NA
5	Public Service Company of Colorado	SF	WSPP-1	NA	NA	NA
6	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
7	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
8	Redding, CIty of	SF	WSPP-1	NA	NA	NA
9	Roseville, City of	SF	WSPP-1	NA	NA	NA
10	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
11	San Diego Gas & Electric Company	SF	WSPP-1	NA	NA	NA
12	Seattle City Light	SF	WSPP-1	NA	NA	NA
13	Sempra Corporation	SF	WSPP-1	NA	NA	NA
14	Shell Energy NA	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
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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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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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sierra Pacific Power	SF	WSPP-1	NA	NA	NA
2	Silicon Valley Power	SF	WSPP-1	NA	NA	NA
3	Snohomish County, PUD No 1, Washington	SF	WSPP-1	NA	NA	NA
4	Southern California Edison	SF	PGE-11	NA	NA	NA
5	Tacoma, City of	SF	WSPP-1	NA	NA	NA
6	The Energy Authority	SF	WSPP-1	NA	NA	NA
7	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
8	TransCanada Power	SF	WSPP-1	NA	NA	NA
9	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
10	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
11						
12	Direct Acess deferral-2009			NA	NA	NA
13	Biglow 2 test energy sales			NA	NA	NA
14	Direct Access amortization-2008			NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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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						
2	Portland General Electric Company	SF	OA96137	363	NA	NA
3						
4						
5						
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
	740,091	157,153		897,244	2
					3
69,291		2,548,127		2,548,127	4
72,440		2,822,236		2,822,236	5
26		588		588	6
382		16,331		16,331	7
300,182		11,900,819		11,900,819	8
21,998		728,464		728,464	9
44,128		1,037,925		1,037,925	10
137,299		6,084,637		6,084,637	11
169,831		3,528,027		3,528,027	12
69,749		2,444,771		2,444,771	13
1,796		58,980		58,980	14
0	740,091	157,153	0	897,244	
7,582,641	7,883,029	266,596,286	-1,207,889	273,271,426	
7,582,641	**8,623,120**	**266,753,439**	**-1,207,889**	**274,168,670**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,845		44,737		44,737	1
38,071		1,333,866		1,333,866	2
24,568		775,057		775,057	3
72,225		1,486,590		1,486,590	4
705		26,745		26,745	5
3,966		118,821		118,821	6
25		1,325		1,325	7
124,780		421,497		421,497	8
91,000		3,078,224		3,078,224	9
53,465	5,630,000	1,642,737		7,272,737	10
23,606		598,552		598,552	11
29,861		1,021,475		1,021,475	12
549,793		31,249,235		31,249,235	13
139,752		4,878,194		4,878,194	14
0	740,091	157,153	0	897,244	
7,582,641	7,883,029	266,596,286	-1,207,889	273,271,426	
7,582,641	**8,623,120**	**266,753,439**	**-1,207,889**	**274,168,670**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES FOR RESALE (Account 447) (Continued)

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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.
25,200		1,349,644		1,349,644	1
17,472		633,081		633,081	2
			916,324	916,324	3
18,402		494,700		494,700	4
79,054		2,540,620		2,540,620	5
21,506		666,104		666,104	6
17,080		550,402		550,402	7
476,831		17,492,968		17,492,968	8
1,968		46,227		46,227	9
682		28,282		28,282	10
568,183		4,668,820		4,668,820	11
20		760		760	12
9,525		421,130		421,130	13
5,655		154,960		154,960	14
0	740,091	157,153	0	897,244	
7,582,641	7,883,029	266,596,286	-1,207,889	273,271,426	
7,582,641	**8,623,120**	**266,753,439**	**-1,207,889**	**274,168,670**	

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.
14,894			211,892	211,892	1
122,496		4,463,821		4,463,821	2
477,744		15,356,726		15,356,726	3
798,262		25,352,388		25,352,388	4
12,400		502,700		502,700	5
208,652		8,926,604		8,926,604	6
5,935		220,933		220,933	7
3,931		143,276		143,276	8
70		3,084		3,084	9
76,086		2,332,465		2,332,465	10
6,921		670,149		670,149	11
11,552		372,297		372,297	12
442,295		29,421,067		29,421,067	13
517,256		17,893,850		17,893,850	14
0	740,091	157,153	0	897,244	
7,582,641	7,883,029	266,596,286	-1,207,889	273,271,426	
7,582,641	**8,623,120**	**266,753,439**	**-1,207,889**	**274,168,670**	

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
36,836		892,877		892,877	1
9,085		305,089		305,089	2
5,625		204,320		204,320	3
22,736		795,236		795,236	4
1,050		26,495		26,495	5
5,848		201,875		201,875	6
1,477,430		50,513,627		50,513,627	7
14,015		517,642		517,642	8
6,374		233,049		233,049	9
10,315		321,888		321,888	10
					11
			893,076	893,076	12
-16,178			-456,841	-456,841	13
			-2,772,340	-2,772,340	14
0	740,091	157,153	0	897,244	
7,582,641	7,883,029	266,596,286	-1,207,889	273,271,426	
7,582,641	**8,623,120**	**266,753,439**	**-1,207,889**	**274,168,670**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
28,649	2,253,029	29,170		2,282,199	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	740,091	157,153	0	897,244	
7,582,641	7,883,029	266,596,286	-1,207,889	273,271,426	
7,582,641	**8,623,120**	**266,753,439**	**-1,207,889**	**274,168,670**	

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

Certificate of Concurrence in Fale-Safe's Tariff No. 1 has been filed with FERC.

Schedule Page: 310.1 Line No.: 10 Column: b

The contract with the City of Glendale expires on 9/30/2012.

Schedule Page: 310.2 Line No.: 3 Column: j

Represents the value of energy received by the PGE control area from Electricity Service Suppliers in deficit of the ESS's actual load within the PGE control area.

Schedule Page: 310.3 Line No.: 1 Column: j

Estimated Round Butte plant operating expenses (Cove Dam replacement power).

Schedule Page: 310.4 Line No.: 12 Column: j

Defer costs associated with the implementation of the 2009 annual direct access open enrollment window. See OPUC Docket #UM 1301 filed 1/23/2009.

Schedule Page: 310.4 Line No.: 13 Column: j

Biglow 2 Wind test energy sales reclassified to capital.

Schedule Page: 310.4 Line No.: 14 Column: j

Amortization of deferred costs associated with the implementation of the 2008 annual direct access open enrollment window. See OPUC Docket #UM 1359 filed 12/12/2007.

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

Represents Portland General Electric Company use of Portland General Electric Company's Open Access Transmission System. This is included in Account 447 based on guidance from FERC Deputy Chief Accountant - issued January 1996.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	9,760,084	9,659,332
5	(501) Fuel	55,400,250	64,991,736
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	1,316,006	1,663,198
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	66,476,340	76,314,266
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	16,447,006	19,215,115
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant	64,643	80,609
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	16,511,649	19,295,724
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	82,987,989	95,609,990
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	5,026,730	4,265,341
45	(536) Water for Power	207,432	459,009
46	(537) Hydraulic Expenses	2,434,954	2,479,056
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,800,000	647,891
49	(540) Rents	1,354,509	212,027
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	10,823,625	8,063,324
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	3,101,342	3,088,651
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,049,706	1,095,617
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,151,048	4,184,268
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	14,974,673	12,247,592

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	7,402,333	7,931,800
63	(547) Fuel	287,861,571	294,238,201
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses	5,446,491	5,149,746
66	(550) Rents	573,138	280,487
67	TOTAL Operation (Enter Total of lines 62 thru 66)	301,283,533	307,600,234
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	19,398,734	14,637,795
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	124,007	76,178
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	19,522,741	14,713,973
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	320,806,274	322,314,207
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	680,506,141	790,015,293
77	(556) System Control and Load Dispatching	2,854,993	3,010,957
78	(557) Other Expenses	9,935,927	10,251,756
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	693,297,061	803,278,006
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,112,065,997	1,233,449,795
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,750,992	2,818,997
84	(561) Load Dispatching	811	575
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	605,073	664,303
87	(561.3) Load Dispatch-Transmission Service and Scheduling	790,802	769,374
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	41,710	94,934
90	(561.6) Transmission Service Studies	377	6,224
91	(561.7) Generation Interconnection Studies	159,266	128,465
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	24,494	28,327
94	(563) Overhead Lines Expenses		
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	65,753,799	65,018,191
97	(566) Miscellaneous Transmission Expenses	2,282,200	2,284,874
98	(567) Rents	2,190,281	1,654,059
99	TOTAL Operation (Enter Total of lines 83 thru 98)	74,599,805	73,468,323
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	1,499,921	1,653,103
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,064,374	811,459
108	(571) Maintenance of Overhead Lines	1,567,827	2,127,357
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,132,122	4,591,919
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	78,731,927	78,060,242

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	9,161,480	10,038,461
135	(581) Load Dispatching		
136	(582) Station Expenses	669,254	320,535
137	(583) Overhead Line Expenses		
138	(584) Underground Line Expenses	1,879,710	1,959,839
139	(585) Street Lighting and Signal System Expenses	3,000,785	2,818,902
140	(586) Meter Expenses	1,018,648	1,009,492
141	(587) Customer Installations Expenses	1,428,803	2,118,355
142	(588) Miscellaneous Expenses	510,836	181,307
143	(589) Rents	1,454,888	1,663,275
144	TOTAL Operation (Enter Total of lines 134 thru 143)	19,124,404	20,110,166
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,328,734	1,251,476
147	(591) Maintenance of Structures	297,091	188,967
148	(592) Maintenance of Station Equipment	3,301,099	3,396,427
149	(593) Maintenance of Overhead Lines	29,353,802	29,152,090
150	(594) Maintenance of Underground Lines	4,304,246	5,057,973
151	(595) Maintenance of Line Transformers		
152	(596) Maintenance of Street Lighting and Signal Systems		
153	(597) Maintenance of Meters	27,947	69,545
154	(598) Maintenance of Miscellaneous Distribution Plant	10,586,489	10,415,370
155	TOTAL Maintenance (Total of lines 146 thru 154)	49,199,408	49,531,848
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	68,323,812	69,642,014
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	3,667,722	5,867,005
161	(903) Customer Records and Collection Expenses	39,307,626	40,847,808
162	(904) Uncollectible Accounts	9,267,650	8,247,937
163	(905) Miscellaneous Customer Accounts Expenses	4,534,934	4,216,923
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	56,777,932	59,179,673

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	6,951,629	6,883,907
169	(909) Informational and Instructional Expenses	2,359,133	2,595,722
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	9,310,762	9,479,629
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	35,469,748	42,801,321
182	(921) Office Supplies and Expenses	17,920,489	21,924,739
183	(Less) (922) Administrative Expenses Transferred-Credit	11,724,879	12,604,680
184	(923) Outside Services Employed	5,268,084	6,546,605
185	(924) Property Insurance	5,482,755	4,256,999
186	(925) Injuries and Damages	4,604,939	7,532,462
187	(926) Employee Pensions and Benefits	40,345,378	35,095,123
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	7,853,865	8,697,043
190	(929) (Less) Duplicate Charges-Cr.	2,028,712	1,918,421
191	(930.1) General Advertising Expenses	1,219,309	1,188,713
192	(930.2) Miscellaneous General Expenses	4,809,496	4,447,478
193	(931) Rents	4,251,175	4,007,112
194	TOTAL Operation (Enter Total of lines 181 thru 193)	113,471,647	121,974,494
195	Maintenance		
196	(935) Maintenance of General Plant	1,608,301	1,690,269
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	115,079,948	123,664,763
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,440,290,378	1,573,476,116

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	Avista Corp	SF	WSPP-1	NA	NA	NA
2	Barclays Bank PC	SF	WSPP-1	NA	NA	NA
3	BC Hydro	SF	WSPP-1	NA	NA	NA
4	Black Hills Power	SF	WSPP-1	NA	NA	NA
5	Bonneville Power Administration	SF	92375	NA	NA	NA
6	Bonneville Power Administration	EX	PGE-202	NA	NA	NA
7	BP Energy Company	SF	PGE-11	NA	NA	NA
8	Burbank, City of	SF	WSPP-1	NA	NA	NA
9	California Independent System Operator	SF	WSPP-1	NA	NA	NA
10	Calpine Energy Services	SF	PGE-11	NA	NA	NA
11	Cargill Alliant LLC	SF	WSPP-1	NA	NA	NA
12	Chelan County, PUD No.1, Washington	LU	Rocky Reach	NA	NA	NA
13	Chelan County, PUD No.1, Washington	SF	WSPP-1	NA	NA	NA
14	Chelan County, PUD No.1, Washington	EX	PGE-71	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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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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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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)	Average Monthly CP Demand (f)
1	Clatskanie County PUD, Washington	SF	WSPP-1	NA	NA	NA
2	Conoco Phillips	SF	WSPP-1	NA	NA	NA
3	CP Energy Marketing (US)	SF	PGE-11	NA	NA	NA
4	Constellation Energy Commodities	SF	PGE-11	NA	NA	NA
5	Covanta Marion	LU	QF83-118	NA	NA	NA
6	Douglas County, PUD No.1, Washington	LU	Wells	NA	NA	NA
7	Douglas County, PUD No.1, Washington	LF	Wells	NA	NA	NA
8	Douglas County, PUD No. 1 Washington	SF	WSPP-1	NA	NA	NA
9	Endure Energy, LLC	SF	WSPP-1	NA	NA	NA
10	EnMax	SF	WSPP-1	NA	NA	NA
11	ESI Vansycle Partners, LP	LF	WSPP-1	NA	NA	NA
12	Eugene Water & Electric Board	LF	WSPP-1	10	10	10
13	Eugene Water & Electric Board	OS	ER94-717	NA	NA	NA
14	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
	Total					

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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.

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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	Eugene Water & Electric Board	EX	WSPP-1	NA	NA	NA
2	Fale-Safe Corporation	RQ	PGE-1	NA	NA	NA
3	Fortis Energy	SF	WSPP-1	NA	NA	NA
4	Glendale, City of	SF	WSPP-1	NA	NA	NA
5	Glendale, City of	EX	PGE-78	NA	NA	NA
6	Grant County PUD No. 2, Washington	LU	Wanapum	NA	NA	NA
7	Grant County PUD No. 2, Washington	LU	Priest Rapids	NA	NA	NA
8	Grant County PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
9	Iberdrola Renewables	SF	WSPP-1	NA	NA	NA
10	Iberdrola Renewables	LF	WSPP-1	NA	NA	NA
11	Idaho Power Company	SF	WSPP-1	NA	NA	NA
12	J. Aron Company	SF	PGE-11	NA	NA	NA
13	JP Morgan Ventures	SF	WSPP-1	NA	NA	NA
14	Load Balance Energy	OS	OATT	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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	Los Angeles Depart Water Power	SF	WSPP-1	NA	NA	NA
2	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
3	Merrill Lynch Commodities	SF	WSPP-1	NA	NA	NA
4	Mirant Americas Energy Marketing	SF	WSPP-1	NA	NA	NA
5	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
6	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
7	Morgan Stanley Capital Group	LF	PGE-11	NA	NA	NA
8	Northern California Power Agency	SF	WSPP-1	NA	NA	NA
9	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
10	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
11	Pacific Gas & Electric Company	SF	WSPP-1	NA	NA	NA
12	Pacific Northwest Generating Company	SF	WSPP-1	NA	NA	NA
13	PacifiCorp	RQ	PP&L 147	NA	NA	NA
14	PacifiCorp	SF	PGE-11	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	Portland, City of	LU	#2821	NA	NA	NA
2	Portland, City of	LU	QF83-448	NA	NA	NA
3	Powerex	SF	PGE-11	NA	NA	NA
4	PPL Energy Plus	SF	PGE-11	NA	NA	NA
5	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
6	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
7	Redding, City of	SF	WSPP-1	NA	NA	NA
8	Roseville, City of	SF	WSPP-1	NA	NA	NA
9	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
10	San Diego Gas & Electric Company	SF	WSPP-1	NA	NA	NA
11	Seattle City Light	SF	WSPP-1	NA	NA	NA
12	Sempra Corporation	SF	WSPP-1	NA	NA	NA
13	Shell Energy	SF	WSPP-1	NA	NA	NA
14	Sierra Power Company	SF	WSPP-1	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	Silicon Valley Power	SF	WSPP-1	NA	NA	NA
2	Snohmish County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
3	Southern California Edison	SF	PGE-11	NA	NA	NA
4	Spokane Energy, LLC	LF	PGE-82	150	150	144
5	Spokane Energy, LLC	EX	PGE-82	NA	NA	NA
6	Tacoma, City of	SF	WSPP-1	NA	NA	NA
7	The Energy Authority	SF	WSPP-1	NA	NA	NA
8	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
9	TransAlta Energy Marketing	LF	PGE-11	NA	NA	NA
10	TransCanada Energy Marketing	SF	WSPP-1	NA	NA	NA
11	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
12	Warm Springs Power Enterprises	LF	WSPP-1	NA	NA	NA
13	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
14	Lake Oswego Corporation	LU	201	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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	Douglas Pegar	OS	201	NA	NA	NA
2	Domaine Drouhin	OS	201	NA	NA	NA
3	Von Land Co	OS	201	NA	NA	NA
4	Minikahada Hydropower Company	OS	201	NA	NA	NA
5	SunWay LLC	OS	201	NA	NA	NA
6	Tualatin Valley Water District	OS	201	NA	NA	NA
7	Oregon Heat	OS	203	NA	NA	NA
8	Non-trading mark to market			NA	NA	NA
9	Margin on Electric Financials			NA	NA	NA
10	Reserve Trading Credit Risk			NA	NA	NA
11	Green Power			NA	NA	NA
12						
13	Non-cash exchanges					
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.
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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)	
50,673				2,622,501		2,622,501	1
113,550				2,853,270		2,853,270	2
128				6,248		6,248	3
51				1,534		1,534	4
339,912				13,680,623		13,680,623	5
	1,242	1,392					6
75,800				2,019,060		2,019,060	7
17,231				692,700		692,700	8
100,058				1,492,083		1,492,083	9
41,468				1,266,287		1,266,287	10
73,936				2,718,550		2,718,550	11
634,145				8,346,006		8,346,006	12
1,609				79,313		79,313	13
	67,814	81,038					14
15,550,554	500,893	513,912	19,642,200	509,477,031	151,386,910	680,506,141	

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.

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,623				105,902		105,902	1
41,290				1,618,675		1,618,675	2
3,236				83,630		83,630	3
27,680				600,241		600,241	4
87,524				5,615,889		5,615,889	5
611,375				7,691,879		7,691,879	6
112,880				2,627,630		2,627,630	7
1,058				19,707		19,707	8
400				22,000		22,000	9
683				26,489		26,489	10
71,332				4,116,903		4,116,903	11
			1,030,200			1,030,200	12
809							13
154,655				1,324,602		1,324,602	14
15,550,554	500,893	513,912	19,642,200	509,477,031	151,386,910	680,506,141	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	26,201	26,371					1
1,914							2
19,600				660,300		660,300	3
1,339				35,747		35,747	4
	415	460					5
475,309				11,377,145		11,377,145	6
911,110				20,853,660		20,853,660	7
70,747				3,168,306		3,168,306	8
783,753				37,402,508		37,402,508	9
220,627				10,426,545		10,426,545	10
143,936				4,612,363		4,612,363	11
11,200				106,400		106,400	12
16,782				435,669		435,669	13
58,713				1,236,246		1,236,246	14
15,550,554	500,893	513,912	19,642,200	509,477,031	151,386,910	680,506,141	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

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

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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)	
961				44,500		44,500	1
26,372				706,263		706,263	2
4,656				104,555		104,555	3
9,037				275,983		275,983	4
3,020				86,232		86,232	5
3,372,588				105,529,773		105,529,773	6
219,000				9,417,000		9,417,000	7
551				11,167		11,167	8
394,244				189,849		189,849	9
570				8,265		8,265	10
3,875				137,180		137,180	11
383,147				9,152,463		9,152,463	12
11,309				1,007,357		1,007,357	13
153,801				6,502,505		6,502,505	14
15,550,554	500,893	513,912	19,642,200	509,477,031	151,386,910	680,506,141	

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92,918				4,308,226		4,308,226	1
303				26,930		26,930	2
102,063				5,418,056		5,418,056	3
18,844				726,614		726,614	4
88,410				2,814,268		2,814,268	5
8,092				252,327		252,327	6
1,692				46,450		46,450	7
45				1,745		1,745	8
19,663				642,771		642,771	9
6,755				162,313		162,313	10
77,496				3,624,213		3,624,213	11
1,363,569				68,610,411		68,610,411	12
685,967				24,070,252		24,070,252	13
6,161				234,035		234,035	14
15,550,554	500,893	513,912	19,642,200	509,477,031	151,386,910	680,506,141	

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

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1,553				63,520		63,520	1
6,700				190,455		190,455	2
45,055				1,914,924		1,914,924	3
			18,612,000			18,612,000	4
	405,221	404,651					5
18,918				623,883		623,883	6
11,536				290,870		290,870	7
1,708,870				59,777,689		59,777,689	8
841,667				32,202,449		32,202,449	9
3,993				111,431		111,431	10
10,663				283,996		283,996	11
550,246				19,527,277		19,527,277	12
13,927				275,863		275,863	13
171				19,378		19,378	14
15,550,554	500,893	513,912	19,642,200	509,477,031	151,386,910	680,506,141	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
473				28,823		28,823	1
74				6,720		6,720	2
184				12,352		12,352	3
276				17,707		17,707	4
909				65,225		65,225	5
94				6,155		6,155	6
					1,358	1,358	7
					-30,619,094	-30,619,094	8
					175,188,825	175,188,825	9
					-565,345	-565,345	10
					7,377,712	7,377,712	11
							12
					3,454	3,454	13
							14
15,550,554	500,893	513,912	19,642,200	509,477,031	151,386,910	680,506,141	

Schedule Page: 326 Line No.: 12 Column: c
Non jurisdictional utilities.

Schedule Page: 326 Line No.: 12 Column: g
Includes allocation to Canadian Entitlement and Fish Spill
Replacement re: Pacific Northwest Coordination
Agreement Canadian Entitlement
-PUD NO.1 Chelan County (38,483)

Schedule Page: 326.1 Line No.: 6 Column: c
Non jurisdictional utilities.

Schedule Page: 326.1 Line No.: 7 Column: b
The Douglas County contract expires on 8/31/2018.

Schedule Page: 326.1 Line No.: 11 Column: b
The ESI Vansycle Partners, LP contract expires 11/06/2028.

Schedule Page: 326.1 Line No.: 12 Column: b
The Eugene Water and Electric Board Memorandum of Understanding expires 12/31/2013.

Schedule Page: 326.1 Line No.: 13 Column: g
Represents net of energy generated at EWEB's Stone Creek facility within PGE's control area and energy delivered to EWEB.

Schedule Page: 326.1 Line No.: 14 Column: c
Non jurisdictional utilities.

Schedule Page: 326.2 Line No.: 2 Column: c
Certificate of Concurrence in Fale-Safe's Tariff No.1 has been filed with FERC.

Schedule Page: 326.2 Line No.: 6 Column: c
Non jurisdictional utilities.

Schedule Page: 326.2 Line No.: 6 Column: g
Includes allocation to Canadian Entitlement and Fish Spill
Replacement re: Pacific Northwest Coordination
Agreement Canadian Entitlement
-PUD NO.2 Grant County (37,574)

Schedule Page: 326.2 Line No.: 10 Column: b
The Iberdrola Renewables Wind contract expires 11/30/2035.

Schedule Page: 326.2 Line No.: 14 Column: a
Represents energy delivered to the PGE control area from Electricity Service Suppliers in excess of their actual load within the PGE control area.

Schedule Page: 326.3 Line No.: 7 Column: b
The Morgan Stanley contract expires on 09/30/2011.

Schedule Page: 326.5 Line No.: 2 Column: c
Non jurisdictional utilities.

Schedule Page: 326.5 Line No.: 4 Column: b
The Spokane Energy, LLC contact expires on 12/31/2016.

Schedule Page: 326.5 Line No.: 9 Column: b
The TransAlta Energy Marketing contract expires on 09/30/2016.

Schedule Page: 326.5 Line No.: 12 Column: b
The Warm Springs contract expires on 02/29/2012.

Schedule Page: 326.5 Line No.: 14 Column: b
Power purchased from customers who operate generation facilities with less than 100 KW capacity.

Schedule Page: 326.6 Line No.: 1 Column: b
Power purchased from customers who operate generation facilities with less than 100 KW capacity.

Schedule Page: 326.6 Line No.: 2 Column: b
Power purchased from customers who operate generation facilities with less than 100 KW capacity.

Schedule Page: 326.6 Line No.: 3 Column: b
Power purchased from customers who operate generation facilities with less than 100 KW

capacity.

Schedule Page: 326.6 Line No.: 4 Column: b

Power purchased from customers who operate generation facilities with less than 100 KW capacity.

Schedule Page: 326.6 Line No.: 5 Column: b

Power purchased from customers who operate generation facilities with less than 100 KW capacity.

Schedule Page: 326.6 Line No.: 6 Column: b

Power purchased from customers who operate generation facilities with less than 100 KW capacity.

Schedule Page: 326.6 Line No.: 7 Column: l

In accordance with Schedule 203 tariff any excess credits will be transferred to Low Income Assistance Program.

Schedule Page: 326.6 Line No.: 8 Column: l

Net unrealized FAS 133 MTM valuation on retail power contracts.

Schedule Page: 326.6 Line No.: 9 Column: l

Margin on electric financial transactions.

Schedule Page: 326.6 Line No.: 10 Column: l

Reserve for trading credit risk.

Schedule Page: 326.6 Line No.: 11 Column: l

Expenses related to the development of new green power generating resources.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Avista Corp-Washington Water Power	Bonneville Power Administration	Various Utilities	LFP
2	Barclay's Bank PLC	Bonneville Power Administration	Various Utilities	NF
3	Bonneville Power Administration	Bonneville Power Administration	Western Oregon Electric Coop	OLF
4	Bonneville Power Administration	Bonneville Power Administration	Western Oregon Electric Coop	OS
5	Bonneville Power Administration	Bonneville Power Administration	Columbia River PUD	FNO
6	Cargill Power and Gas	Bonneville Power Administration	Various Utilities	SFP
7	Cargil Power and Gas	Bonneville Power Administration	Various Utilities	NF
8	Citigroup Energy LP	Bonneville Power Administration	Various Utilities	AD
9	ConocoPhillips Inc.	Bonneville Power Administration	Various Utilities	NF
10	Constellation Energy Commodities	Bonneville Power Administration	Portland General Electric	SFP
11	Constellation New Energy	Bonneville Power Administration	Portland General Electric	NF
12	Constellation New Energy	Bonneville Power Administration	Portland General Electric	AD
13	Shell Energy North America	Bonneville Power Administration	Various Utilities	NF
14	Shell Energy North America	Bonneville Power Administration	Various Utilities	LFP
15	Shell Energy North America	Bonneville Power Administration	Various Utilities	OS
16	Shell Energy North America	Bonneville Power Administration	Various Utilities	FNO
17	EPCOR Merchant and Capital US	Bonneville Power Administration	Portland General Electric	NF
18	EPCOR Merchant and Capital US	Bonneville Power Administration	Portland General Electric	AD
19	Iberdrola Renewables Inc.	Bonneville Power Administration	Portland General Electric	NF
20	JP Morgan Ventures Energy	Bonneville Power Administration	Various Utilities	NF
21	Morgan Stanley Capital Group	Bonneville Power Administration	Various Utilities	NF
22	PacifiCorp	PacifiCorp	Bonneville Power Administration	OS
23	PacifiCorp	PacifiCorp	Bonneville Power Administration	AD
24	PacifiCorp	Portland General Electric	PacifiCorp	OLF
25	Powerex	Bonneville Power Administration	Various Utilities	LFP
26	Powerex	Bonneville Power Administration	Various Utilities	SFP
27	Powerex	Bonneville Power Administration	Various Utilities	NF
28	Powerex	Bonneville Power Administration	Various Utilities	OS
29	Powerex	Bonneville Power Administration	Various Utilities	AD
30	Puget Sound Energy	Bonneville Power Administration	Various Utilities	NF
31	Puget Sound Energy	Bonneville Power Administration	Various Utilities	AD
32	Rainbow Energy Marketing Corp.	Bonneville Power Administration	Various Utilities	NF
33	San Diego Gas and Electric	Bonneville Power Administration	Various Utilities	OLF
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Seattle City Light	Bonneville Power Administration	Various Utilities	NF
2	Sempra Energy Solutions	Bonneville Power Administration	Portland General Electric	NF
3	Sempra Energy Trading Co.	Bonneville Power Administration	Portland General Electric	NF
4	Sempra Energy Solutions	Bonneville Power Administration	Portland General Electric	AD
5	Sempra Energy Trading Co.	Bonneville Power Administration	Various Utilities	AD
6	Snohomish County PUD	Bonneville Power Administration	Various Utilities	NF
7	Tacoma Power	Bonneville Power Administration	Various Utilities	NF
8	Tacoma Power	Bonneville Power Administration	Various Utilities	AD
9	The Energy Authority	Bonneville Power Administration	Various Utilities	NF
10	TransAlta Energy Marketing US	Bonneville Power Administration	Various Utilities	NF
11	TransAlta Energy Marketing US	Bonneville Power Administration	Various Utilities	SFP
12	TransAlta Energy Marketing US	Bonneville Power Administration	Various Utilities	OS
13	TransAlta Energy Marketing US	Bonneville Power Administration	Various Utilities	AD
14	TransAlta Energy Marketing US	Bonneville Power Administration	Various Utilities	AD
15	Turlock Irrigation District	Bonneville Power Administration	Various Utilities	NF
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
OA96137	BPA-John Day Sub	PGE-Malin Sub	100	709,559	709,559	1
OA96137	BPA-John Day Sub	PGE-Malin Sub		1,480	1,480	2
72	Various BPA Subs	Various PGE Subs		443,190	442,510	3
72	BPA-Oregon City Sub	PGE-Canby				4
OA96137	BPA-St. Johns Tap	PGE-St. Helens/Scap.	12	75,497	73,092	5
OA96137	BPA-John Day Sub	PGE-Malin Sub	4			6
OA96137	BPA-John Day Sub	PGE-Malin Sub		621	621	7
OA96137	BPA-John Day Sub	PGE-Malin Sub				8
OA96137	BPA-John Day Sub	PGE-Malin Sub		286	286	9
OA96137	Various PGE Subs	Various PGE Subs	275			10
OA96137	Various PGE Subs	Various PGE Subs		35,069	29,435	11
OA96137	Various PGE Subs	Various PGE Subs				12
OA96137	BPA-John Day Sub	PGE-Malin Sub		8,145	8,145	13
OA96137	BPA-John Day Sub	PGE-Malin Sub	200	944,206	944,206	14
OA96137	PGE-Malin Sub	BPA-John Day Sub		11,115	11,115	15
OA96137	BPA-John Day Sub	PGE-Malin Sub				16
OA96137	Various PGE Subs	Various PGE Subs	11	74,126	71,439	17
OA96137	Various PGE Subs	Various PGE Subs				18
OA96137	Various PGE Subs	Various PGE Subs		400	400	19
OA96137	BPA-John Day Sub	PGE-Malin Sub				20
OA96137	BPA-John Day Sub	PGE-Malin Sub		374	374	21
109	BPA-Bethel	PacifiCorp-Linneman		3,685	3,685	22
109	BPA-Bethel	PacifiCorp-Linneman				23
109	PGE-Grand Ronde	PGE-Grand Ronde				24
OA96137	BPA-John Day Sub	PGE-Malin Sub	165	603,406	603,406	25
OA96137	BPA-John Day Sub	PGE-Malin Sub	380	10,392	10,392	26
OA96137	BPA-John Day Sub	PGE-Malin Sub		34,210	34,210	27
OA96137	BPA-John Day Sub	PGE-Malin Sub		956	956	28
OA96137	BPA-John Day Sub	PGE-Malin Sub				29
OA96137	BPA-John Day Sub	PGE-Malin Sub		11,106	11,106	30
OA96137	BPA-John Day Sub	PGE-Malin Sub				31
OA96137	BPA-John Day Sub	PGE-Malin Sub		60	60	32
OA96137	BPA-John Day Sub	PGE-Malin Sub	13	48,881	48,881	33
						34
			1,812	**5,063,985**	**5,035,351**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
OA96137	BPA-John Day Sub	PGE-Malin Sub		1,052	1,052	1
OA96137	Various PGE Subs	Various PGE Subs	293	1,901,668	1,884,440	2
OA96137	BPA-John Day Sub	PGE-Malin Sub		10,235	10,235	3
OA96137	Various PGE Subs	Various PGE Subs				4
OA96137	BPA-John Day Sub	PGE-Malin Sub				5
OA96137	BPA-John Day Sub	PGE-Malin Sub		1,454	1,454	6
OA96137	BPA-John Day Sub	PGE-Malin Sub		17	17	7
OA96137	BPA-John Day Sub	PGE-Malin Sub				8
OA96137	BPA-John Day Sub	PGE-Malin Sub		153	153	9
OA96137	BPA-John Day Sub	PGE-Malin Sub		104,060	104,060	10
OA96137	BPA-John Day Sub	PGE-Malin Sub	359	27,989	27,989	11
OA96137	PGE-Malin Sub	BPA-John Day Sub		593	593	12
OA96137	BPA-John Day Sub	PGE-Malin Sub				13
OA96137	BPA-John Day Sub	PGE-Malin Sub				14
OA96137	BPA-John Day Sub	PGE-Malin Sub				15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			1,812	**5,063,985**	**5,035,351**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
642,989			642,989	1
	1,805		1,805	2
	532,902		532,902	3
23,544			23,544	4
42,725			42,725	5
82			82	6
	716		716	7
		-36	-36	8
	484		484	9
5,613			5,613	10
	46,302		46,302	11
		-1,732	-1,732	12
	11,664		11,664	13
1,285,978			1,285,978	14
				15
		-75	-75	16
	58,891		58,891	17
		-613	-613	18
	294		294	19
	161		161	20
	334		334	21
	266,877		266,877	22
		-20,529	-20,529	23
1,097			1,097	24
1,067,771			1,067,771	25
21,806			21,806	26
	68,221		68,221	27
				28
		-31,768	-31,768	29
	12,991		12,991	30
		-5,073	-5,073	31
	76		76	32
650,000			650,000	33
				34
3,792,377	**2,707,120**	**-83,327**	**6,416,170**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	1,057		1,057	1
	1,570,235		1,570,235	2
	10,387		10,387	3
		-16,000	-16,000	4
		-14	-14	5
	1,815		1,815	6
	39		39	7
		-41	-41	8
	508		508	9
	121,360		121,360	10
50,772			50,772	11
				12
		-7,521	-7,521	13
		75	75	14
	1		1	15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
3,792,377	**2,707,120**	**-83,327**	**6,416,170**	

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

Contract with Avista Corporation - Washington Water Power expires 01/01/2013.

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

Contract with Bonneville Power Administration continues until terminated.

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

Represents monthly facility usage charges.

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

Contract with Bonneville Power Administration continues until terminated.

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

Contract with Cargill Power and Gas continues until terminated.

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

Respresents billing ajustments for 2009.

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

Short-term firm point-to-point contracts are secured daily via reservations.
Constellation Energy Commodities totals:

	Billing Demand (MW)	Demand Charges
February	275	$5,613

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

In previous years, this has been reported as "FNO" (Firm Network for Others). However the ESS's have been reserving this transmission as Secondary Network, which is not Firm Network. For year end and future quarterly reporting, we will report this as "NF" (Non-Firm) because it is not firm and it does not fall under the category "OS" (Other Service).

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

Represents true-up for 2008 services.

Schedule Page: 328 Line No.: 14 Column: d

Contract with Shell Energy North America expires 06/01/2013.

Schedule Page: 328 Line No.: 15 Column: d

Represents non-billed redirected MWHs of Shell Energy North America's LFP reservations.

Schedule Page: 328 Line No.: 16 Column: d

Represents true-up for 2008 services.

Schedule Page: 328 Line No.: 17 Column: d

In previous years, this has been reported as "FNO" (Firm Network for Others). However the ESS's have been reserving this transmission as Secondary Network, which is not Firm Network. For year end and future quarterly reporting, we will report this as "NF" (Non-Firm) because it is not firm and it does not fall under the category "OS" (Other Service).

Schedule Page: 328 Line No.: 18 Column: d

Represents true-up for 2008 services.

Schedule Page: 328 Line No.: 22 Column: d

Represents monthly facility usage charges.

Schedule Page: 328 Line No.: 23 Column: d

Represents true-up for 2008 services.

Schedule Page: 328 Line No.: 24 Column: d

Contract with PacifiCorp continues until terminated.

Schedule Page: 328 Line No.: 25 Column: d

Contract with Powerex expires 06/01/2013.

Schedule Page: 328 Line No.: 26 Column: d

Short-term firm point-to-point contracts
are secured daily via reservations.
Powerex SFP totals:

	Billing Demand (MW)	Demand Charges
January	383	$ 7,526
June	352	6,656
July	380	7,623
Total		$21,806

Schedule Page: 328 Line No.: 28 Column: d

Represents non-billed redirected MWHs of Powerex's SFP reservations.

Schedule Page: 328 Line No.: 29 Column: d

Represents true-up for 2008 services.

Schedule Page: 328 Line No.: 31 Column: d

Respresents billing ajustments for 2009.

Schedule Page: 328 Line No.: 33 Column: d

Contract with San Diego Gas & Electric expires 12/31/2013.

Schedule Page: 328.1 Line No.: 2 Column: d

In previous years, this has been reported as "FNO" (Firm Network for Others). However, the ESS's have been reserving this transmission as Secondary Network, which is not Firm Network. For year end and future quarterly reporting, we will report this as "NF" (Non-Firm) because it is not firm and it does not fall under the category "OS" (Other Service).

Schedule Page: 328.1 Line No.: 4 Column: d

Represents true-up for 2008 services.

Schedule Page: 328.1 Line No.: 5 Column: d

Represents true-up for 2008 services.

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

Represents true-up for 2008 services.

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

Short-term firm point-to-point contracts are secured daily via reservations.
TransAlta Energy Marketing's SFP totals:

	Billing Demand (MW)	Demand Charges
January	242	$ 4,939
February	393	8,021
March	52	1,061
April	44	898
May	33	674
June	176	3,328
July	359	7,195

December	1208	24,656
Total		$ 50,772

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

Represents non-billed redirected MWHs of TransAlta Energy Marketing's SFP reservations.

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

Respresents billing ajustments for 2009.

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

Represents true-up for 2008 services.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp	NF	3,579	3,579		14,860		14,860
2	Bonneville Power Admin	OLF			40,755,397			40,755,397
3	Bonneville Power Admin	LFP			15,182,549			15,182,549
4	Bonneville Power Admin	OS					6,151,023	6,151,023
5	Bonneville Power Admin	NF	128,484	128,484		365,987		365,987
6	BPA Amortization	FNS					196,416	196,416
7	Chelan PUD	NF	2	2		61		61
8	Columbia River PUD	NF	8,857	8,857		5,160		5,160
9	Fale-Safe, Inc	OS					1,039,234	1,039,234
10	Idaho Power Company	NF	12,374	12,374		6,887		6,887
11	McMinnville Water & Lig	NF	1,755	1,755		6,645		6,645
12	Montana, State of	OS					845,132	845,132
13	Northwestern Corp	NF	37,419	37,419		166,540		166,540
14	NorthWest Power Pool	OS					23,610	23,610
15	PacifiCorp	OS					103,752	103,752
16	PacifiCorp	NF	808,705	808,705		834,254		834,254
	TOTAL		1,019,054	1,019,054	55,937,946	1,432,570	8,383,283	65,753,799

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Puget Sound Energy	NF	17,879	17,879		32,176		32,176
2	Salem Electric	OS					24,116	24,116
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		1,019,054	1,019,054	55,937,946	1,432,570	8,383,283	65,753,799

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2009/Q4

FOOTNOTE DATA

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

The Bonneville Power Administration IR contract expires on 12/31/2009. This IR contract is replaced by Bonneville Power Administration PTP contract which expires on 12/31/2014.

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

The Bonneville Power Administration PTP contract for John Day and Big Eddy expires on 09/30/2015, the PTP contract for Rocky Reach expires on 05/31/2015, the PTP contract for Vansycle expires on 11/30/2016, PTP contract for Slatt expires 12/31/2013.

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

Represents Bonneville Power Administration Ancillary Transmission Services.

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

Represents amortization of deferred transmission costs related to transmission line access for the Glendale sales agreement, amortized over 25 years through 2012.

Schedule Page: 332 Line No.: 9 Column: g

Represents payment for certain Fale-Safe obligations, net of interst income, in exchange for additional access to Interie.

Schedule Page: 332 Line No.: 12 Column: g

Represents Beneficial Use Tax and Wholesale Energy Transaction Tax payments to the State of Montana for the use of BPA's transmission lines.

Schedule Page: 332 Line No.: 14 Column: g

Represents Ancillary Services under the Pacific Northwest Coordinating Agreement.

Schedule Page: 332 Line No.: 15 Column: g

Represents PacifiCorp's Linneman Transmission Services.

Schedule Page: 332.1 Line No.: 2 Column: g

Represents Ancillary Services provided by Salem Electric.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,953,162
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	361,544
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	809,926
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Involuntary Severence	511,604
7	Directors Pension	49,014
8	Directors Fees & Expenses	1,117,087
9	Misc Admin R&D Expenses	7,159
10		
11		
12		
13		
14		
15		
16		
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45		
46	TOTAL	4,809,496

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

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			15,718,809		15,718,809
2	Steam Production Plant	11,755,418	16,557			11,771,975
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	5,303,358	64			5,303,422
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	38,982,410	23,957			39,006,367
7	Transmission Plant	10,144,520	1,676			10,146,196
8	Distribution Plant	104,115,115	9,615			104,124,730
9	Regional Transmission and Market Operation					
10	General Plant	13,940,418	2,079			13,942,497
11	Common Plant-Electric					
12	TOTAL	184,241,239	53,948	15,718,809		200,013,996

B. Basis for Amortization Charges

Five-year and ten-year amortization of computer software.
Five-year and twenty-five year amortization of permits.
Thirty-year and fifty-year amortization of hydro relicensing costs.

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	Note: Complete data						
13	will be provided in						
14	the 2011 Form 1						
15	(5 year interval)						
16							
17							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	FERC-California Refund		42,971	42,971	
2	Docket No's. EL00-95, EL00-1451, ER01-889,				
3	RTO1-85 Consolidated				
4					
5	FERC-Compliance Audit		265,792	265,792	
6	Docket No. PA06-9				
7					
8	FERC-OATT Investigation		166,348	166,348	
9	Docket No. PA06-9				
10					
11	OPUC-In The Matters of Rulemaking Implement SB		48,694	48,694	
12	838 Relating to Renewable Portfolio Standard				
13	Docket No. AR-518				
14					
15	OPUC-Investigation Forecasting Forced Outage		35,608	35,608	
16	Rates for Electric Generating Units				
17	Docket No. UM-1355				
18					
19	OPUC-Renewable Adjustment Clause		31,315	31,315	
20	Docket No. UE-209				
21					
22	OPUC-Request to Add Schedule 111 AMI		27,697	27,697	
23	(Advanced Metering Infrastructure)				
24	Docket No. UE-189				
25					
26	OPUC-SB 408 Implementation Tax Adjustment		56,441	56,441	
27	Docket No. AR-499				
28					
29	OPUC-Selective Water Withdrawal		101,195	101,195	
30	Docket No. UE-204				
31					
32	OPUC-Boardman Deferral Application		90,769	90,769	
33	Docket No. UE-196				
34					
35	FERC matters less than $25,000		56,806	56,806	
36					
37	OPUC matters less than $25,000		137,388	137,388	
38					
39	Non Docs matters less than $25,000		436,689	436,689	
40					
41					
42					
43					
44					
45					
46	TOTAL		1,497,713	1,497,713	

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.
	928	42,971					1
							2
							3
							4
	928	265,792					5
							6
							7
	928	166,348					8
							9
							10
	928	48,694					11
							12
							13
							14
	928	35,608					15
							16
							17
							18
	928	31,315					19
							20
							21
	928	27,697					22
							23
							24
							25
	928	56,441					26
							27
							28
	928	101,195					29
							30
							31
	928	90,769					32
							33
							34
	928	56,806					35
							36
	928	137,388					37
							38
	928	436,689					39
							40
							41
							42
							43
							44
							45
		1,497,713					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
  (1) Generation
    a. hydroelectric
      i. Recreation fish and wildlife
      ii Other hydroelectric
    b. Fossil-fuel steam
    c. Internal combustion or gas turbine
    d. Nuclear
    e. Unconventional generation
    f. Siting and heat rejection
  (2) Transmission
    a. Overhead
    b. Underground
  (3) Distribution
  (4) Regional Transmission and Market Operation
  (5) Environment (other than equipment)
  (6) Other (Classify and include items in excess of $50,000.)
  (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
  (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A(1)	Electric R, D & D Performed Internally - Generation
2	A(1)(d)	Nuclear
3	A(1)(e)	Unconventional Generation
4		
5	A(3)	Electric R, D & D Performed Internally - Distribution
6		
7	A(5)	Electric R, D & D Performed Internally - Environment (other than equip)
8		
9	B(1)	Electric R, D & D Performed Externally
10		Research Support to the Electrical Research Council or EPRI
11		
12		
13		
14		
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29	Totals	
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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 $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
40,000		930.2	40,000		2
56,000		930.2	56,000		3
					4
20,840		930.2	20,840		5
					6
35,000		930.2	35,000		7
					8
					9
	209,704	930.2	209,704		10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
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					26
					27
					28
151,840	209,704		361,544		29
					30
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	24,113,733		
4	Transmission	4,059,460		
5	Regional Market			
6	Distribution	15,237,094		
7	Customer Accounts	29,194,491		
8	Customer Service and Informational	4,219,281		
9	Sales			
10	Administrative and General	32,281,481		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	109,105,540		
12	Maintenance			
13	Production	8,822,010		
14	Transmission	1,167,305		
15	Regional Market			
16	Distribution	17,725,175		
17	Administrative and General	623,488		
18	TOTAL Maintenance (Total of lines 13 thru 17)	28,337,978		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	32,935,743		
21	Transmission (Enter Total of lines 4 and 14)	5,226,765		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	32,962,269		
24	Customer Accounts (Transcribe from line 7)	29,194,491		
25	Customer Service and Informational (Transcribe from line 8)	4,219,281		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	32,904,969		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	137,443,518	15,135,450	152,578,968
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	137,443,518	15,135,450	152,578,968
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	54,484,771	5,382,443	59,867,214
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	54,484,771	5,382,443	59,867,214
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,157,600	10,259	2,167,859
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,157,600	10,259	2,167,859
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	2,961,277	164,052	3,125,329
79	Co-owner shares of Generating Facilities	8,370,744	348,395	8,719,139
80	Other	3,229,995	122,685	3,352,680
81	Payroll Allocated	21,163,284	-21,163,284	
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	35,725,300	-20,528,152	15,197,148
96	TOTAL SALARIES AND WAGES	229,811,189		229,811,189

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2009/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	152,709	153,104	440,315	1,492,083
3	Net Sales (Account 447)	961,261	847,899	1,531,278	5,272,674
4	Transmission Rights				
5	Ancillary Services	492,736	147,746	89,954	811,964
6	Other Items (list separately)				
7					
8					
9					
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43					
44					
45					
46	TOTAL	1,606,706	1,148,749	2,061,547	7,576,721

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	16,165	MW	5,325,133	2,987,729	Various	104,310
2	Reactive Supply and Voltage	16,165	MW	613,461	2,758,313	Various	88,388
3	Regulation and Frequency Response				2,758,251	Various	205,861
4	Energy Imbalance	47,938	MW-Hour	1,239,072	22,607	MW-Hour	930,310
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	80,268		7,177,666	8,526,900		1,328,869

Schedule Page: 398 Line No.: 1 Column: g

Scheduling, System Control and Dispatch		
No. of Units	Unit of Measure	Amount
2,758,104	Sum of Peak Demand (KW)	$ 27,581
219,997	MW-Hour	3,595
147	MW-Month	1,836
3,901	MW-Day	1,599
5,580	MW-Year	69,699
2,987,729		$104,310

Schedule Page: 398 Line No.: 2 Column: g

Reactive Supply and Voltage		
No of Units	Unit of Measure	Amount
2,758,104	Sum of Peak Demand (KW)	$ 82,743
62	MW-Hour	0.19
147	MW-Month	5,645
2,758,313		$ 88,388

Schedule Page: 398 Line No.: 3 Column: g

Regulation and Frequency Response		
No of Units	Unit of Measure	Amount
2,758,104	Sum of Peak Demand (KW)	$193,067
147	MW-Month	12,794
2,758,251		$205,861

Schedule Page: 398 Line No.: 4 Column: d

The Energy Imbalance Cost (EIC) is equal to the market price of energy for each hour based on the published Dow Jones Electricity Price Index Mid-Columbia daily non-firm on-peak or off-peak price.

Schedule Page: 398 Line No.: 4 Column: g

The Energy Imbalance Cost (EIC) is equal to the market price of energy for each hour based on the published Dow Jones Electricity Price Index Mid-Columbia daily non-firm on-peak or off-peak price.

Schedule Page: 398 Line No.: 8 Column: b

Total is not meaningful because it represents a summation of amounts of dissimilar units of measure.

Schedule Page: 398 Line No.: 8 Column: e

Total is not meaningful because it represents a summation of amounts of dissimilar units of measure.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: PGE

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,069	19	1900	3,126	221	1,515	13	900	6
2	February	4,103	2	800	3,036	224	1,515	13	847	
3	March	3,633	9	900	2,856	236	1,347	13	750	
4	Total for Quarter 1	11,805			9,018	681	4,377	39	2,497	6
5	April	3,555	1	1100	2,663	214	1,347	13	750	
6	May	3,607	29	1700	2,680	268	1,347	13	750	150
7	June	3,638	3	1700	2,761	258	1,347	13	750	50
8	Total for Quarter 2	10,800			8,104	740	4,041	39	2,250	200
9	July	4,644	28	1700	3,673	291	1,347	13	750	
10	August	4,299	19	1700	3,342	291	1,347	13	750	75
11	September	3,637	30	2000	2,351	252	1,347	13	750	67
12	Total for Quarter 3	12,580			9,366	834	4,041	39	2,250	142
13	October	3,334	13	2000	2,524	255	1,347	13	750	58
14	November	3,700	13	1800	2,705	263	1,347	13	750	
15	December	4,789	10	800	3,609	255	1,347	13	1,150	162
16	Total for Quarter 4	11,823			8,838	773	4,041	39	2,650	220
17	Total Year to Date/Year	47,008			35,326	3,028	16,500	156	9,647	568

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: Colstrip

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	267	10	2400		307				
2	February	262	2	200		307				
3	March	265	9	600		307				
4	Total for Quarter 1	794				921				
5	April	193	29	2400		307				
6	May	148	26	2000		307				
7	June	241	16	2300		307				
8	Total for Quarter 2	582				921				
9	July	174	25	2400		307				
10	August	183	20	600		307				
11	September	147	7	400		307				
12	Total for Quarter 3	504				921				
13	October	259	30	2300		307				
14	November	260	21	400		307				
15	December	261	27	100		307				
16	Total for Quarter 4	780				921				
17	Total Year to Date/Year	2,660				3,684				

Schedule Page: 400 Line No.: 17 Column: g

Long Term Firm Point-to-Point Reservation:

Reservation #	Customer	January Capacity	February Capacity	March Capacity	Earliest Termination Date
315999	Avista Corporation	200	200	200	1/1/2022
432190	Portland General Electric	200	200	200	1/1/2012
71260874	Portland General Electric	650	650		3/1/2009
71260876	Portland General Electric	200	200		3/1/2009
71324505	Powerex	165	165	165	6/1/2013
71324658	Avista Corporation	100	100	100	1/1/2013
72905627	Portland General Electric			480	3/1/2010
72905632	Portland General Electric			200	3/1/2010
72905636	Portland General Electric			2	3/1/2010
	Total	1515	1515	1347	

Long Term Firm Point-to-Point Reservation:

Reservation #	Customer	April Capacity	May Capacity	June Capacity	Earliest Termination Date
432190	Portland General Electric	200	200	200	1/1/2012
71324505	Powerex	165	165	165	6/1/2013
71324658	Avista Corporation	100	100	100	1/1/2013
71472976	Shell Energy North America	200	200	200	1/1/2022
72905627	Portland General Electric	480	480	480	3/1/2010
72905632	Portland General Electric	200	200	200	3/1/2010
72905636	Portland General Electric	2	2	2	3/1/2010
	Total	1347	1347	1347	

Long Term Firm Point-to-Point Reservation:

Reservation #	Customer	July Capacity	August Capacity	September Capacity	Earliest Termination Date
315999	Avista Corporation	200	200	200	1/1/2022
432190	Portland General Electric	200	200	200	1/1/2012

71324505	Powerex	165	165	165	6/1/2013
71324658	Avista Corporation	100	100	100	1/1/2013
72905627	Portland General Electric	480	480	480	3/1/2010
72905632	Portland General Electric	200	200	200	3/1/2010
72905636	Portland General Electric	2	2	2	3/1/2010
	Total	1347	1347	1347	

Long Term Firm Point-to-Point
Reservation:

Reservation #	Customer	October Capacity	November Capacity	December Capacity	Earliest Termination Date
315999	Avista Corporation	200	200	200	1/1/2022
432190	Portland General Electric	200	200	200	1/1/2012
71324505	Powerex	165	165	165	6/1/2013
71324658	Avista Corporation	100	100	100	1/1/2013
72905627	Portland General Electric	480	480	480	3/1/2010
72905632	Portland General Electric	200	200	200	3/1/2010
72905636	Portland General Electric	2	2	2	3/1/2010
	Total	1347	1347	1347	

Schedule Page: 400 Line No.: 17 Column: h

Other Long
Term Service:

	Customer	Capacity	Earliest Termination Date
Grandfathered	SEMPRA (San Diego Gas & Electric)	13	12/31/2020

Schedule Page: 400 Line No.: 17 Column: i

Short-Term Firm Point-to-Point Transmission Service Requests at date and time of monthly Transmission Service Peak for Q1:

Reservation #	Customer	January Capacity	February Capacity	March Capacity
72743746	Portland General Electric	150		
72743747	Portland General Electric	600		
72811112	Powerex	97		
72812377	Powerex	53		
72836232	Portland General Electric		150	
72836231	Portland General Electric		600	
72845814	TransAlta Energy		97	

72899128	Portland General Electric			150
72899133	Portland General Electric			600
	Total	900	847	750

Short-Term Firm Point-to-Point Transmission Service Requests at date and time of monthly Transmission Service Peak for Q2:

Reservation #	Customer	April Capacity	May Capacity	June Capacity
72969400	Portland General Electric	150		
72969403	Portland General Electric	600		
73042949	Portland General Electric		150	
73042951	Portland General Electric		600	
73110916	Portland General Electric			150
73110918	Portland General Electric			600
	Total	750	750	750

Short-Term Firm Point-to-Point Transmission Service Requests at date and time of monthly Transmission Service Peak for Q3:

Reservation #	Customer	July Capacity	August Capacity	September Capacity
73186849	Portland General Electric	150		
73186855	Portland General Electric	600		
73276894	Powerex		150	
73276896	Powerex		600	
73355691	Portland General Electric			150
73355697	Portland General Electric			600
	Total	750	750	750

Short-Term Firm Point-to-Point Transmission Service Requests at date and time of monthly Transmission Service Peak for Q4:

Reservation #	Customer	October Capacity	November Capacity	December Capacity
73186849	Portland General Electric	150		
73186855	Portland General Electric	600		
73276894	Powerex		150	
73276896	Powerex		600	
73355691	Portland General Electric			150
73355697	Portland General Electric			600
73656975	Transalta Energy Marketing US Inc.			250
73659367	Portland General Electric			150
	Total	750	750	1150

Schedule Page: 400 Line No.: 17 Column: j

Other
Service:
The entries represent the total amount scheduled under non-firm reservations (daily and/or hourly) at the date and time of transmission system peak for each month. (NONFIRM SCHEDULES)

Schedule Page: 400.1 Line No.: 16 Column: b

Monthly Peak MW:
These entries are the "Transmission Provider's Monthly Transmission System Peak" as defined in PGE's OATT in Section 1.47, the maximum firm

usage of PGE's share of the Colstrip transmission system facilities
during the calendar month.

Schedule Page: 400.1 Line No.: 16 Column: f

Firm Network
Service for
Others:

Reservation #	Customer	Capacity	Earliest Termination Date
73065442	Portland General Electric	27	07/01/2022
73068563	Portland General Electric	280	07/01/2022

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	3,759,989
4	Nuclear	
5	Hydro-Conventional	1,800,401
6	Hydro-Pumped Storage	
7	Other	4,998,371
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	10,558,761
10	Purchases	15,550,554
11	Power Exchanges:	
12	Received	500,893
13	Delivered	513,912
14	Net Exchanges (Line 12 minus line 13)	-13,019
15	Transmission For Other (Wheeling)	
16	Received	5,063,985
17	Delivered	5,035,351
18	Net Transmission for Other (Line 16 minus line 17)	28,634
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	26,124,930

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	17,419,212
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	7,553,992
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	25,501
27	Total Energy Losses	1,126,225
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	26,124,930

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

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	2,485,378	640,789	3,460	26	1900
30	February	2,183,927	625,072	3,315	10	1900
31	March	2,385,827	753,749	3,143	11	800
32	April	2,001,019	583,837	2,829	1	800
33	May	1,918,679	541,676	2,895	29	1700
34	June	2,242,128	910,978	2,966	3	1800
35	July	2,239,209	623,420	3,949	29	1600
36	August	2,184,709	696,853	3,573	19	1700
37	September	1,992,091	593,513	3,036	11	1700
38	October	2,020,365	584,417	2,775	29	1900
39	November	2,090,710	570,913	3,058	30	1800
40	December	2,352,254	483,791	3,851	7	1900
41	TOTAL	26,096,296	7,609,008			

Schedule Page: 401 Line No.: 7 Column: b

Includes 498,846 megawatt hours of net wind generation from PGE's Biglow Canyon Wind Project Phase I, which went into service in 2007, and Phase II, which went into service in 2009. Key statistics related to the project include the following:

In-service Production cost at 12/31/2009: $542,071,785
Total installed capacity: 275 megawatts
Operations and Maintenance expenses for 2009: $7,580,398

Schedule Page: 401 Line No.: 29 Column: c

Energy losses associated with Sales for Resale have been estimated. This note applies to column (C), lines 29-40.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Boardman* (b)	Plant Name: *Boardman* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1980	1980
4	Year Last Unit was Installed	1980	1980
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	642.20	417.43
6	Net Peak Demand on Plant - MW (60 minutes)	599	0
7	Plant Hours Connected to Load	5695	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	575	0
10	When Limited by Condenser Water	575	0
11	Average Number of Employees	112	0
12	Net Generation, Exclusive of Plant Use - KWh	3159247000	2046588000
13	Cost of Plant: Land and Land Rights	1240068	798843
14	Structures and Improvements	152856712	100927122
15	Equipment Costs	489558594	314437075
16	Asset Retirement Costs	4963619	4193722
17	Total Cost	648618993	420356762
18	Cost per KW of Installed Capacity (line 17/5) Including	1009.9953	1007.0114
19	Production Expenses: Oper, Supv, & Engr	7567507	4974219
20	Fuel	53067361	34702584
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	1930679	1276587
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	16619501	10068645
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	96765	64643
34	Total Production Expenses	79281813	51086678
35	Expenses per Net KWh	0.0251	0.0250

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Composite			
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels				
38	Quantity (Units) of Fuel Burned	1870231	5774	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8517	138600	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	29.217	85.572	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	26.907	130.423	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.580	22.405	1.602	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.016	0.000	0.016	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10083.900	10.600	10094.500	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: *Colstrip* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear				Steam		
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			311.20		
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			1713401000		
13	Cost of Plant: Land and Land Rights	0			3327909		
14	Structures and Improvements	0			114717556		
15	Equipment Costs	0			310835574		
16	Asset Retirement Costs	0			128481		
17	Total Cost	0			429009520		
18	Cost per KW of Installed Capacity (line 17/5) Including	0.0000			1378.5653		
19	Production Expenses: Oper, Supv, & Engr	0			4785865		
20	Fuel	0			20697666		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			39419		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			6378361		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			31901311		
35	Expenses per Net KWh	0.0000			0.0186		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	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/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Beaver* (d)			Plant Name: *Port Westward* (e)			Plant Name: *Coyote Springs* (f)			Line No.
Gas & Steam Turbine			Gas & Steam Turbine			Gas & Steam Turbine			1
Outdoor			Outdoor			Outdoor			2
1974			2007			1995			3
2001			2007			1995			4
610.70			483.30			266.40			5
501			421			257			6
1761			6910			6396			7
0			0			0			8
545			424			244			9
0			0			0			10
52			21			25			11
451054000			2638393000			1410078000			12
0			0			0			13
29793529			42109026			10761800			14
167752073			215057114			144000386			15
42315			226391			112544			16
197587917			257392531			154874730			17
323.5433			532.5730			581.3616			18
1659142			2801148			2599038			19
49450074			150567880			86626057			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
3387273			494355			776235			26
178849			33882			67405			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
2361922			5893354			5901289			32
86790			29909			7309			33
57124050			159820528			95977333			34
0.1266			0.0606			0.0681			35
Gas	Oil	Composite	Gas	Oil	Composite	Gas	Oil	Composite	36
Mcf's	Barrels		Mcf's	Barrells		Mcf's	Barrell		37
4415731	1853	0	18363258	0	0	10695461	0	0	38
1011000	138600	0	1011000	138600	0	1011000	138600	0	39
3.551	0.000	0.000	4.290	0.000	0.000	3.823	0.000	0.000	40
3.551	48.266	0.000	4.290	0.000	0.000	3.823	0.000	0.000	41
3.512	8.302	0.000	4.243	0.000	0.000	3.781	0.000	0.000	42
0.035	0.000	0.035	0.030	0.000	0.030	0.029	0.000	0.029	43
9898.700	23.900	9922.600	7037.400	0.000	7037.400	7669.400	0.000	7669.400	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (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	0	0	17
0.0000	0.0000	0.0000	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	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: b

Respondent is the principal owner (65 percent interest) and operator of the Boardman Plant. The other owners include Idaho Power Company (10 percent interest), Power Resources Cooperative (10 percent interest) and General Electric Credit Corporation (15 percent interest). Reported here are 100 percent costs and plant statistics, including shared and non-shared costs.

Schedule Page: 402 Line No.: -1 Column: c

Jointly owned. Installed capacity on line 5 represents 65 percent share. Details are reported on Page 402, col. (b)

Schedule Page: 402 Line No.: 9 Column: d

Based on January Average Temperature

Schedule Page: 402 Line No.: 9 Column: e

Based on January Average Temperature

Schedule Page: 402 Line No.: 9 Column: f

Based on January Average Temperature

Schedule Page: 402.1 Line No.: -1 Column: c

Jointly owned. PP&L Montana, LLC is the joint owner/operator of the plant. Reported herein is respondents's 20 percent share of installed capacity, cost of plant, net generation and production expenses.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 2195 Plant Name: Faraday (c)
1	Kind of Plant (Run-of-River or Storage)		Run-of-River;Storage
2	Plant Construction type (Conventional or Outdoor)		Conventional;Semi-ou
3	Year Originally Constructed		1907
4	Year Last Unit was Installed		1958
5	Total installed cap (Gen name plate Rating in MW)	0.00	36.80
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	48
7	Plant Hours Connect to Load	0	8,759
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	46
10	(b) Under the Most Adverse Oper Conditions	0	39
11	Average Number of Employees	0	43
12	Net Generation, Exclusive of Plant Use - Kwh	0	171,160,000
13	Cost of Plant		
14	Land and Land Rights	0	33,434
15	Structures and Improvements	0	3,246,996
16	Reservoirs, Dams, and Waterways	0	18,370,448
17	Equipment Costs	0	8,194,306
18	Roads, Railroads, and Bridges	0	1,956,781
19	Asset Retirement Costs	0	76
20	TOTAL cost (Total of 14 thru 19)	-33,434	31,802,041
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	864.1859
22	Production Expenses		
23	Operation Supervision and Engineering	0	1,375,255
24	Water for Power	0	20,766
25	Hydraulic Expenses	0	58,111
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	716,956
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	281,474
34	Total Production Expenses (total 23 thru 33)	0	2,452,562
35	Expenses per net KWh	0.0000	0.0143

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2030 Plant Name: Pelton (b)	FERC Licensed Project No. 2030 Plant Name: Pelton (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River;Storage	Run-of-River;Storage
2	Plant Construction type (Conventional or Outdoor)	Semi-Outdoor	Semi-Outdoor
3	Year Originally Constructed	1957	1957
4	Year Last Unit was Installed	1958	1958
5	Total installed cap (Gen name plate Rating in MW)	109.80	73.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	109	0
7	Plant Hours Connect to Load	6,914	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	110	0
10	(b) Under the Most Adverse Oper Conditions	108	0
11	Average Number of Employees	6	0
12	Net Generation, Exclusive of Plant Use - Kwh	414,221,000	276,161,000
13	Cost of Plant		
14	Land and Land Rights	3,672,025	2,448,139
15	Structures and Improvements	7,297,618	4,825,429
16	Reservoirs, Dams, and Waterways	13,313,399	8,894,576
17	Equipment Costs	8,295,699	5,531,474
18	Roads, Railroads, and Bridges	3,174,076	2,120,984
19	Asset Retirement Costs	0	42
20	TOTAL cost (Total of 14 thru 19)	35,752,817	23,820,644
21	Cost per KW of Installed Capacity (line 20 / 5)	325.6176	326.3102
22	Production Expenses		
23	Operation Supervision and Engineering	646,379	544,466
24	Water for Power	47,074	19,279
25	Hydraulic Expenses	627,411	249,255
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	115,540	0
28	Rents	28,532	11,317
29	Maintenance Supervision and Engineering	352,809	145,784
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	180,635	77,594
34	Total Production Expenses (total 23 thru 33)	1,998,380	1,047,695
35	Expenses per net KWh	0.0048	0.0038

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2195 Plant Name: North Fork (d)	FERC Licensed Project No. 2195 Plant Name: River Mill (e)	FERC Licensed Project No. 135 Plant Name: Oak Grove (f)	Line No.
Run-of-River;Stor	Run-of-River;Stor	Run-of-River;Stor	1
Semi-Outdoor	Conventional	Conventional	2
1958	1911	1924	3
1958	1952	1931	4
40.80	18.90	51.00	5
57	27	45	6
8,759	8,759	8,759	7
			8
58	25	44	9
43	20	49	10
0	0	7	11
203,946,000	108,863,000	252,480,000	12
			13
377,100	86,408	9,457	14
3,645,350	2,765,271	4,467,415	15
19,854,060	37,187,506	18,941,069	16
7,921,070	5,358,730	8,105,817	17
1,513,726	458,019	2,056,140	18
5	54	1,769	19
33,311,311	45,855,988	33,581,667	20
816.4537	2,426.2428	658.4641	21
			22
608,911	536,562	848,483	23
23,195	13,829	18,965	24
143,515	89,970	55,965	25
0	0	0	26
0	0	1,800,000	27
81,969	0	1,210,746	28
514,688	368,847	414,452	29
0	0	0	30
0	0	0	31
0	0	0	32
224,654	55,422	116,640	33
1,596,932	1,064,630	4,465,251	34
0.0078	0.0098	0.0177	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2030 Plant Name: Round Butte (d)	FERC Licensed Project No. 2030 Plant Name: Round Butte (e)	FERC Licensed Project No. 2233 Plant Name: Sullivan (f)	Line No.
Storage	Storage	Run-of-River	1
Semi-Outdoor	Semi-Outdoor	Conventional	2
1964	1964	1895	3
1964	1964	1953	4
247.00	165.00	15.40	5
304	0	18	6
6,953	0	8,696	7
			8
338	0	18	9
210	0	9	10
39	0	1	11
976,924,000	651,315,000	136,476,000	12
			13
3,716,284	2,521,011	572,077	14
9,830,994	6,580,537	9,222,412	15
41,363,671	27,576,165	19,788,615	16
20,140,731	13,416,874	12,531,014	17
1,006,573	671,713	0	18
0	106	2,224	19
76,058,253	50,766,406	42,116,342	20
307.9281	307.6752	2,734.8274	21
			22
666,731	583,347	529,706	23
103,835	81,094	30,304	24
2,028,133	1,718,732	119,406	25
0	0	0	26
94,533	0	0	27
64,563	50,477	0	28
846,995	677,610	263,005	29
0	0	0	30
0	0	0	31
0	0	0	32
311,699	227,393	66,529	33
4,116,489	3,338,653	1,008,950	34
0.0042	0.0051	0.0074	35

Schedule Page: 406.1 Line No.: -2 Column: b

Respondent is the principal owner (66.67 percent interest) and operator of the Pelton Plant. The other owner is The Confederated Tribes of The Warm Springs Reservation of Oregon. Reported here are 100 percent costs and plant statistics, including shared and non-shared costs.

Schedule Page: 406.1 Line No.: -2 Column: c

Jointly owned. Installed capacity on line 5 represents 66.67 percent share. Details reported on Page 406.1, column (b).

Schedule Page: 406.1 Line No.: -2 Column: d

Respondent is the principal owner (66.67 percent interest) and operator of the Round Butte Plant. The other owner is The Confederated Tribes of The Warm Springs Reservation of Oregon. Reported here are 100 percent costs and plant statistics, including shared and non-shared costs.

Schedule Page: 406.1 Line No.: -2 Column: e

Jointly owned. Installed capacity on line 5 represents 66.67 percent share. Details reported on Page 407.1, column (d).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Maclaren	1999	0.50	0.4	6	104,631
2	Oregon Military Dept/A.F.R.C	2001	1.60	1.6	27	164,147
3	US Bank Corp Columbia Center	2001	6.40	6.2	248	488,058
4	Providence Business Center	2004	2.00	1.8	32	385,944
5	Portland State University	2004	2.80	2.8	50	261,732
6	Oregon Military Joint Forces HQ	2005	1.60	1.6	35	191,440
7	Stimson Lumber	2005	0.57	0.5	5	152,560
8	FORTIX (ViaWest)	2005	1.00	0.9	22	87,719
9	Skyline	2005	2.00	1.8	56	201,526
10	Tri-Quint	2005	0.60	0.5	11	109,968
11	NCCWC- Filter Plant	2005	2.00	1.8	63	122,958
12	PCC Structurals	2005	1.00	0.9	14	111,039
13	Providence Portland Medical Center	2005	6.00	5.4	270	257,579
14	Salem Hospital	2006	4.00	3.6	277	188,494
15	Sunrise Water Authority Pump Station	2006	1.25	1.1	37	85,879
16	Providence Newberg Hospital	2006	1.50	1.4	45	156,833
17	Sungard DSG	2006	2.00	1.8	25	331,845
18	Kaiser Sunnyside Hospital	2007	4.50	4.0	178	352,752
19	Newberg Waste Water Treatment Plant	2008	2.00	1.8	29	104,165
20	Xerox Corp	2007	4.00	3.6	97	380,259
21	Newberg Water Treatment Plant	2007	1.00	0.9	18	77,037
22	Solaicx	2008	1.00	0.9	7	62,963
23	Solar World	2008	3.00	2.7	76	216,182
24	Total					4,595,711
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
209,263			4,321	diesel-low s	1,900	1
102,592		3,809	13,208	diesel-low s or gas	1,379	2
76,259		18,865	32,580	diesel-low s	1,350	3
192,972		6,993	13,131	diesel-low s	1,293	4
93,476		8,398	24,619	diesel-low s	1,493	5
119,650		1,715	26,030	diesel-low s	1,357	6
270,018		787	14,562	diesel-low s	1,493	7
87,719		7,989	6,048	diesel-low s	1,307	8
100,763		5,086	8,271	diesel-low s	1,207	9
183,279		1,949	9,139	diesel-low s	1,243	10
61,479		8,278	9,048	diesel-low s	1,493	11
111,039		1,075	4,621	diesel-low s	1,079	12
42,930		22,508	26,854	diesel-low s	1,293	13
47,124		10,678	11,971	diesel-low s	1,371	14
68,704		2,085	5,361	diesel-low s	1,407	15
104,555		2,438	12,436	diesel-low s	1,429	16
165,922		4,587	5,547	diesel-low s	1,493	17
78,389		6,658	15,030	diesel-low s	1,371	18
52,082			3,211	diesel-low s	3,214	19
95,065		7,126	15,030	diesel-low s	1,343	20
77,037			17,495	diesel-low s	3,214	21
62,963		458	5,798	diesel-low s	1,636	22
72,061			20,731	diesel-low s	1,357	23
		121,482	305,045			24
						25
						26
						27
						28
						29
						30
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						46

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	500KV LINES							
2	GRIZZLY	ROUND BUTTE	500.00	500.00	ST. TOWER	15.60		1
3	GRIZZLY	MALIN	500.00	500.00	ST. TOWER	178.00		1
4	MISCELLANEOUS	MISCELLANEOUS			-			
5	BOARDMAN	BPA SLATT	500.00	500.00	ST. TOWER	17.80		1
6								
7	COLSTRIP PROJECT:							
8	COLSTRIP SWYD.	BROADVIEW 'A'	500.00	500.00	ST. TOWER		112.30	1
9	COLSTRIP SWYD.	BROADVIEW 'B'	500.00	500.00	ST. TOWER		115.80	1
10	BROADVIEW SWYD.	TOWNSEND 'A'	500.00	500.00	ST. TOWER		133.40	1
11	BROADVIEW SWYD.	TOWNSEND 'B'	500.00	500.00	ST. TOWER		133.40	1
12	Colstrip Project Costs	Project Lines						
13	Tot 500KV Line Expenses							
14								
15	PELTON 230KV PROJECT							
16	PELTON	ROUND BUTTE	230.00	230.00	H-WOOD	7.87		1
17								
18	NON PROJECT 230KV:							
19	BETHEL	ROUND BUTTE	230.00	230.00	H-WOOD	55.19		1
20			230.00	230.00	ST. TOWER	44.85		1
21	ROUND BUTTE	BPA REDMOND	230.00	230.00	H-WOOD	23.60		1
22	BETHEL	BPA TIE (SANTIAM)	230.00	230.00	H-WOOD	3.60		1
23	BETHEL	McLOUGHLIN	230.00	230.00	H-WOOD	35.70		1
24	CARVER	GRESHAM	230.00	230.00	H-WOOD	7.39		1
25	McLOUGHLIN	CARVER	230.00	230.00	H-WOOD	4.95		1
26	McLOUGHLIN	CARVER	230.00	230.00	ST. MONOP	4.88		1
27	BPA KEELER	ST. MARY'S W.	230.00	230.00	H-WOOD	2.89		1
28			230.00	230.00	ST. TOWER	3.78		2
29	BLUE LAKE	TROUTDALE BPA	230.00	230.00	H-WOOD	0.80		1
30			230.00	230.00	ST. MONOP	0.58		1
31	PEARL BPA	SHERWOOD	230.00	230.00	ST. TOWER		4.72	2
32			230.00	230.00	ST. TOWER	0.16		1
33	GRESHAM	LINNEMAN	230.00	230.00	ST. TOWER	0.26		1
34	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER	11.10		1
35			230.00	230.00	H-TOWER	0.60		1
36					TOTAL	590.55	543.22	54

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	NON PROJECT 230KV							
2	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER		4.40	2
3	ST. MARY'S W.	MURRAYHILL	230.00	230.00	ST. TOWER	5.92		1
4	MURRAYHILL	SHERWOOD	230.00	230.00	ST. TOWER	5.68		2
5	PORT WESTWARD	TROJAN	230.00	230.00	ST. MONOP	18.80		1
6			230.00	230.00	ST. MONOP	9.39		1
7	TROJAN	ST. MARY'S W.	230.00	230.00	H-WOOD	0.10		1
8			230.00	230.00	ST. TOWER	3.86		2
9			230.00	230.00	ST. TOWER	4.80		1
10			230.00	230.00	ST. TOWER	33.20		2
11	TROJAN	RIVERGATE	230.00	230.00	ST. TOWER		32.20	2
12			230.00	230.00	ST. TOWER	2.90		2
13	Tot Nonproj 230kv Costs							
14	GRESHAM	TROUTDALE	230.00	230.00	ST. TOWER		7.00	1
15	BOARDMAN	PPL DALREED	230.00	230.00	H-WOOD	16.75		1
16	Tot 230KV LINE EXPENSES							
17								
18	PROJECT 115 KV LINES							
19	FARADAY	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		1
20	NORTH FORK	FARADAY	115.00	115.00	H-WOOD	2.79		1
21	OAK GROVE	FARADAY	115.00	115.00	DC LATTICE	18.68		2
22	OAK GROVE	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		2
23			115.00	115.00	DC LATTICE	18.68		2
24	Tot 115KV LINE EXPENSES							
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	590.55	543.22	54

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
								1
1780MCMACSR	50,953	1,645,820	1,696,773					2
1780MCMACSR	275,427	15,581,384	15,856,811					3
	5,904		5,904					4
1480MCMACSR		4,620,708	4,620,708					5
								6
								7
								8
								9
								10
								11
	1,194,326	42,798,091	43,992,417					12
				772,769	1,475,949	684,891	2,933,609	13
								14
								15
795MCMACSR	7,579	225,598	233,177					16
								17
								18
1272MCMACSR								19
1272MCMACSR								20
795MCMACSR								21
795MCMACSR								22
1272MCMACSR								23
1272MCMAAC								24
1272MCMAAC								25
1272MCMACSS								26
1590MCMACSRTW								27
1590MCMACSRTW								28
1780MCMACSR								29
								30
2388MCMAACTW								31
2388MCMAACTW								32
1272MCMAAC								33
1272MCMAAC								34
1780MCMACSR								35
	10,163,987	129,711,136	139,875,123	1,288,636	2,461,230	774,258	4,524,124	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
								1
1272MCMAAC								2
1272MCMAAC								3
1272MCMAAC								4
2156MCMACSS								5
2156MCMACSS								6
1272MCMAAC								7
1272MCMAAC								8
1590MCMAAC								9
1590MCMAAC								10
1590MCMAAC								11
1272MCMACSR								12
	8,474,778	61,572,054	70,046,832					13
954KCMACSR								14
795KCMAAC		973,248	973,248					15
				515,867	985,281	4,855	1,506,003	16
								17
								18
795KCMACSR		502,020	502,020					19
556KCMACSR	120,248	621,351	741,599					20
250CU	12,477	420,125	432,602					21
795KCMACSR								22
250CU	22,295	750,737	773,032					23
						84,512	84,512	24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	10,163,987	129,711,136	139,875,123	1,288,636	2,461,230	774,258	4,524,124	36

Schedule Page: 422 Line No.: 2 Column: a

Jointly owned with BA Leasing BSC, LLC. Total length is indicated. Costs are respondent's share.

Schedule Page: 422 Line No.: 3 Column: a

Jointly owned with BA Leasing BSC, LLC. Total length is indicated. Costs are respondent's share.

Schedule Page: 422 Line No.: 5 Column: a

Jointly owned with Idaho Power Company, Power Resources Cooperative and BA Leasing BSC, LLC. Total length is indicated. Costs are respondent's share.

Schedule Page: 422 Line No.: 7 Column: a

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.

Schedule Page: 422 Line No.: 13 Column: a

Represents perpetual leases for transmission lines PGE has with the Bonneville Power Administration and for payments made to the FERC per Part 11 - Annual Charges under Part 1 of the Federal Power Act for use of government land as it pertains to transmission lines.

Schedule Page: 422 Line No.: 16 Column: a

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Total length is indicated. Costs are respondent's share.

Schedule Page: 422 Line No.: 31 Column: a

Represents ownership of one circuit on Bonneville Power Administration's double circuit line.

Schedule Page: 422.1 Line No.: 14 Column: a

Represents contract with PacifiCorp whereby PGE is entitled to 1/2 the capacity of the line.

Schedule Page: 422.1 Line No.: 15 Column: a

Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing BSC, LLC. Total length is indicated. Costs are respondent's share.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION 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	Beaver	Trojan	0.41	H-Wood	0.41	1	1
2			18.80	St. Monop	10.86	2	2
3				H-Wood	7.94	1	1
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19	St Marys	Trojan	41.44	St. Tower	1.85	1	2
20				St. Tower	37.62	1	2
21				St. Tower	1.97	1	2
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		60.65		60.65	7	10

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	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)	Asset Retire. Costs (o)	Total (p)	No.
2156	MCMACSS		230			8,697,313		8,697,313	1
2156	MCMACSS		230						2
1780	MCMACSR								3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
1590	MCMACSR		230			1,802,183		1,802,183	19
1590	MCMAAC								20
1780	MCMACSR								21
									22
									23
									24
									25
									26
									27
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									39
									40
									41
									42
									43
						10,499,496		10,499,496	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	14 Substation < 10 MVa capacity at various locat, OR	Distrib./unattended			
2	Abernethy, Oregon City, OR	Distrib./unattended	115.00	13.00	
3	Alder, Portland, OR	Distrib./unattended	115.00	13.00	
4	Amity, near Amity, OR	Distrib./unattended	57.00	13.00	
5	Arleta, Portland, OR	Distrib./unattended	57.00	13.00	
6	Banks, Banks, Or	Distrib./unattended	57.00	13.00	
7	Barnes, Salem, OR	Distrib./unattended	115.00	13.00	
8	Beaverton, Beaverton, OR	Distrib./unattended	115.00	13.00	
9	Bell, near Portland, OR	Distrib./unattended	115.00	13.00	
10	Bethany, Portland, OR	Distrib./unattended	115.00	13.00	
11	Boones Ferry, Lake Oswego, OR	Distrib./unattended	115.00	13.00	
12	Boring, near Boring, OR	Distrib./unattended	57.00	13.00	
13	Brookwood, near Hillsboro, OR	Distrib./unattended	57.00	13.00	
14	Canby, near Barlow, OR	Distrib./unattended	57.00	13.00	
15	Canemah, Oregon City, OR	Distrib./unattended	115.00	57.00	13.00
16	Canyon, Portland, OR	Distrib./unattended	115.00	13.00	
17	Cedar Hills, near Beaverton, OR	Distrib./unattended	115.00	13.00	
18	Centennial, near Gresham, OR	Distrib./unattended	115.00	13.00	
19	Chemawa BPA, near Salem, OR	Distrib./unattended	115.00		
20	Chemawa BPA, near Salem, OR	Distrib./unattended	57.00		
21	Clackamas, Clackamas, OR	Distrib./unattended	115.00	13.00	
22	Claxtar, Salem,OR	Distrib./unattended	57.00	13.00	
23	Coffee Creek, Sherwood, OR	Distrib./unattended	115.00	13.00	
24	Cornelius, Cornelius, OR	Distrib./unattended	115.00	57.00	13.00
25	Cornelius, Cornelius, OR	Distrib./unattended	57.00	13.00	
26	Culver, Salem, OR	Distrib./unattended	115.00	12.50	
27	Curtis, Portland, OR	Distrib./unattended	115.00	13.00	
28	Curtis, Portland, OR	Distrib./unattended	13.00	11.00	
29	Dayton, near Dayton , OR	Distrib./unattended	115.00	57.00	13.00
30	Dayton, near Dayton , OR	Distrib./unattended	57.00	13.00	
31	Delaware, Portland, OR	Distrib./unattended	115.00	13.00	
32	Delaware, Portland, OR	Distrib./unattended	115.00	11.00	4.16
33	Denny, Beaverton, OR	Distrib./unattended	115.00	13.00	
34	Dilley, near Forest Grove, OR	Distrib./unattended	57.00	13.00	
35	Dunn's Corner, near Sandy,OR	Distrib./unattended	57.00	13.00	
36	Durham, Tigard , OR	Distrib./unattended	115.00	13.00	
37	E., East Yard, Portland, OR	Distrib./unattended	115.00	13.00	
38	E., East Yard, Portland, OR	Distrib./unattended	115.00	11.00	
39	E., West Yard, Portland, OR	Distrib./unattended	115.00	13.00	
40	E., West Yard, Portland, OR	Distrib./unattended	115.00	11.00	

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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	Eagle Creek, Eagle Creek, OR	Distrib./unattended	57.00	13.00	
2	Eastport, Portland, OR	Distrib./unattended	115.00	13.00	
3	Elma, near Salem, OR	Distrib./unattended	57.00	13.00	
4	Estacada, Estacada, OR	Distrib./unattended	57.00	12.50	
5	Fairmount, Salem, OR	Distrib./unattended	115.00	13.00	
6	Fairview, Fairview, OR	Distrib./unattended	115.00	13.00	
7	Forest Grove BPA, Forest Grove, OR	Distrib./unattended	115.00		
8	Garden Home, near Portland, OR	Distrib./unattended	115.00	13.00	
9	Glencoe, Portland, OR	Distrib./unattended	115.00	13.00	
10	Glencullen, Portland, OR	Distrib./unattended	115.00	13.00	
11	Glendoveer, near Portland, OR	Distrib./unattended	115.00	13.00	
12	Glisan, Gresham, OR	Distrib./Unattended	115.00	13.00	
13	Grand Ronde, Grand Ronde, OR	Distrib./unattended	115.00	57.00	13.00
14	Grand Ronde, Grand Ronde, OR	Distrib./unattended	115.00	13.00	
15	Harborton, near Portland, OR	Distrib./unattended	115.00	13.00	
16	Harmony, near Milwaukie, OR	Distrib./unattended	115.00	13.00	
17	Harrison Sub, Portland, OR	Distrib./unattended	115.00	13.00	
18	Harrison Sub, Portland, OR	Distrib./unattended	57.00	11.00	4.16
19	Hayden Island, near Portland, OR	Distrib./unattended	115.00	13.00	
20	Hemlock, Portland, Or	Distrib./unattended	115.00	13.00	
21	Hillcrest, Salem , OR	Distrib./unattended	115.00	13.00	
22	Hillsboro, Hillsboro , OR	Distrib./unattended	57.00	13.00	
23	Hogan North, Gresham, OR	Distrib./unattended	115.00	13.00	
24	Hogan South, Gresham, OR	Distrib./unattended	115.00	57.00	13.00
25	Hogan South, Gresham, OR	Distrib./unattended	115.00	13.00	
26	Holgate, Portland, OR	Distrib./unattended	57.00	13.00	
27	Huber, near Beaverton, OR	Distrib./unattended	115.00	13.00	
28	Indian, near Salem, OR	Distrib./unattended	115.00	13.00	
29	Island, near Milwaukie, OR	Distrib./unattended	115.00	13.00	
30	Jennings Lodge, Jennings Lodge, OR	Distrib./unattended	115.00	13.00	
31	Kelley Point, Portland, OR	Distrib./unattended	115.00	13.00	
32	Kelly Butte, Portland, OR	Distrib./unattended	115.00	13.00	
33	King City, near King City, OR	Distrib./unattended	115.00	13.00	
34	Leland, Oregon City, OR	Distrib./unattended	57.00	13.00	
35	Lents, near Portland, OR	Distrib./unattended	115.00	13.00	
36	Lents, near Portland, OR	Distrib./unattended	57.00	11.00	
37	Lents, near Portland, OR	Distrib./unattended	13.00	11.00	
38	Liberty, Salem, OR	Distrib./unattended	115.00	13.00	
39	Main, Hillsboro, OR	Distrib./unattended	57.00	13.00	
40	Market Street, Salem, OR	Distrib./unattended	115.00	12.50	

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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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	McClain, Salem, OR	Distrib./unattended	57.00	13.00	
2	Meridian, near Tualatin, OR	Distrib./unattended	115.00	13.00	
3	Middle Grove, near Middle Grove, OR	Distrib./unattended	57.00	13.00	
4	Midway, near Portland, OR	Distrib./unattended	115.00	13.00	
5	Mill Creek, near Salem, OR	Distrib./unattended	115.00	13.00	
6	Molalla, Molalla, OR	Distrib./unattended	57.00	13.00	
7	Mt. Angel, Mt. Angel, OR	Distrib./unattended	57.00	13.00	
8	Mt. Pleasant, Oregon City , OR	Distrib./unattended	115.00	13.00	
9	Multnomah, Portland, OR	Distrib./unattended	115.00	13.00	
10	Murrayhill, Beaverton, OR	Distrib./unattended	115.00	13.00	
11	Newberg, Newberg, OR	Distrib./unattended	115.00	13.00	
12	North Marion, near Woodburn, OR	Distrib./unattended	57.00	13.00	
13	North Plains, North Plains, OR	Distrib./unattended	57.00	13.00	
14	Northern, Portland, OR	Distrib./unattended	57.00	11.00	
15	Oak Hills, near Beaverton, OR	Distrib./unattended	115.00	13.00	
16	Oregon City - BPA, near Wilsonville, OR	Distrib./unattended	57.00		
17	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	57.00	13.00
18	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
19	Orient, near Gresham, OR	Distrib./unattended	57.00	13.00	
20	Oswego, Lake Oswego, OR	Distrib./unattended	115.00	13.00	
21	Oxford, Salem, OR	Distrib./unattended	115.00	13.00	
22	Pleasant Valley, near Portland, OR	Distrib./unattended	115.00	12.50	
23	Portable No. 3, OR	Distrib./unattended	115.00	57.00	13.00
24	Portable No. 5, OR	Distrib./unattended	115.00	57.00	13.00
25	Portable No. 7, OR	Distrib./unattended	115.00	57.00	12.50
26	Portsmouth, Portland, OR	Distrib./unattended	115.00	13.00	
27	Progress, near Tigard, OR	Distrib./unattended	115.00	13.00	
28	Raleigh Hills, near Portland, OR	Distrib./unattended	115.00	13.00	
29	Ramapo, near Portland, OR	Distrib./unattended	115.00	13.00	
30	Redland, near Oregon City, OR	Distrib./unattended	115.00	13.00	
31	Reedville, near Beaverton, OR	Distrib./unattended	115.00	13.00	
32	Rhodendron Switching, OR	Distrib./unattended	57.00		
33	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	13.00	
34	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	11.00	
35	Riverview, Portland, OR	Distrib./unattended	115.00	13.00	
36	Rockwood, near Gresham, OR	Distrib./unattended	115.00	13.00	
37	Rosemont, near Lake Oswego, OR	Distrib./unattended	115.00		
38	Roseway, Hillsboro, OR	Distrib./unattended	115.00	13.00	
39	Ruby, North, Gresham, OR	Distrib./unattended	57.00		
40	Ruby, South, Gresham, OR	Distrib./unattended	57.00	13.00	

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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	Salem-PGE, near Salem, OR	Distrib./unattended	57.00	13.00	
2	Sandy, Sandy, OR	Distrib./unattended	57.00	13.00	
3	Scappoose, Scappoose, OR	Distrib./unattended	115.00		
4	Scoggin, near Gaston, OR	Distrib./unattended	57.00	13.00	
5	Sellwood, Portland, OR	Distrib./unattended	115.00	57.00	13.00
6	Sellwood, Portland, OR	Distrib./unattended	115.00	13.00	
7	Sheridan, Sheridan, OR	Distrib./unattended	57.00	13.00	
8	Silverton, Silverton, OR	Distrib./unattended	57.00	13.00	
9	Six Corners, Six Corners, OR	Distrib./unattended	115.00	13.00	
10	Springbrook, Newberg, OR	Distrib./unattended	115.00	13.00	
11	Springdale, near Springdale, OR	Distrib./unattended		12.50	
12	St. Helens, near St. Helens, OR	Distrib./unattended	115.00		
13	St. Johns-BPA, near Portland, OR	Distrib./unattended		11.00	
14	St. Louis, St. Louis, OR	Distrib./unattended	57.00	13.00	
15	St. Marys, East Yard, near Beaverton, OR	Distrib./unattended	115.00	13.00	
16	Stephens, Portland, OR	Distrib./unattended	57.00	13.00	
17	Stephens, Portland, OR	Distrib./unattended	57.00	11.00	
18	Stephens, Portland, OR	Distrib./unattended	11.00	4.15	
19	Sullivan, West Linn, OR	Distrib./unattended	115.00	13.00	
20	Summit, Government Camp, OR	Distrib./unattended	57.00	13.00	
21	Summit, Government Camp, OR	Distrib./unattended	24.00	13.00	
22	Sunset, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
23	Swan Island, Portland, OR	Distrib./unattended	115.00	13.00	
24	Sylvan, near Portland, OR	Distrib./unattended	115.00	13.00	
25	Tabor, Portland, OR	Distrib./unattended	115.00	13.00	
26	Tabor, Portland, OR	Distrib./unattended	57.00		
27	Tektronix, Beaverton, OR	Distrib./unattended	115.00	13.00	
28	Tigard, Tigard, OR	Distrib./unattended	115.00	12.50	
29	Town Center, Portland, OR	Distrib./unattended	115.00	13.00	
30	Tualitin, Tualitin, OR	Distrib./unattended	115.00	13.00	
31	Twilight, Canby, OR	Distrib./unattended	57.00	13.00	
32	University, Salem, OR	Distrib./unattended	115.00	13.00	
33	Urban, Portland, OR	Distrib./unattended	115.00	13.00	
34	Waconda, near Hopmere, OR	Distrib./unattended	57.00	12.50	
35	Welches, near Welches, OR	Distrib./unattended	57.00	24.00	13.00
36	Welches, near Welches, OR	Distrib./unattended	57.00	13.00	
37	West Portland, Lower Yard, near Tigard, OR	Distrib./unattended	115.00		
38	West Portland, Upper Yard, near Tigard, OR	Distrib./unattended	115.00	13.00	
39	West Union, near Hillsboro, OR	Distrib./unattended	57.00	12.50	
40	Willamina, near Willamina, OR	Distrib./unattended	57.00	13.00	

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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	Willbridge, Portland, OR	Distrib./unattended	115.00	11.00	
2	Wilsonville, near Wilsonville, OR	Distrib./unattended	57.00	13.00	
3	Woodburn, Woodburn, OR	Distrib./unattended	57.00	13.00	
4	Yamhill, near Yamhill, OR	Distrib./unattended	57.00	13.00	
5					
6					
7					
8	Allston, BPA, near Mayger, OR	Transm./unattended	230.00		
9	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	13.00	
10	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	24.00	
11	Bethel, Salem, OR	Transm./unattended	230.00	115.00	13.00
12	Bethel, Salem, OR	Transm./unattended	115.00	57.00	13.00
13	Bethel, Salem, OR	Transm./unattended	115.00	13.00	
14	Biglow Canyon Windfarm	Transm./unattended	230.00	34.50	13.80
15	Blue Lake, Troutdale, OR	Transm./unattended	230.00	115.00	13.00
16	Blue Lake, Troutdale, OR	Transm./unattended	115.00	13.00	
17	Boardman, near Boardman, OR	Transm./unattended	500.00	24.00	
18	Boardman, OR	Transm./unattended	230.00	7.20	
19	Boardman, OR	Transm./unattended	24.00	7.20	
20	Broadview Subst. near Broadview, MT	Transm./unattended	500.00	230.00	
21	Carver, Carver, OR	Transm./unattended	230.00	115.00	13.00
22	Carver, Carver, OR	Transm./unattended	115.00	13.00	
23	Colstrip Plant, near Colstrip, MT	Transm./unattended	500.00	26.00	
24	Colstrip Subst. near Colstrip, MT	Transm./unattended	500.00	230.00	
25	Coyote Springs, Boardman, OR	Transm./unattended	500.00		
26	Faraday, Switchyard, OR	Transm./unattended	115.00	57.00	12.50
27	Faraday, Switchyard, OR	Transm./unattended	57.00	11.00	
28	Faraday Plant, near Estacada, OR	Transm./unattended	115.00	12.50	
29	Fort Rock, approx 12 mi NE of Silver Lake, OR	Transm./unattended	500.00		
30	Gresham, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
31	Grizzly, BPA, near Madras, OR	Transm./unattended	500.00		
32	Linneman, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
33	Malin, BPA, near Malin, OR	Transm./unattended	500.00		
34	McLoughlin, near Oregon City, OR	Transm./unattended	230.00	115.00	13.00
35	Monitor, near Monitor, OR	Transm./unattended	230.00	57.00	13.00
36	Murryhill, Beaverton, OR	Transm./unattended	230.00	115.00	13.00
37	North Fork, near Estacada, OR	Transm./unattended	115.00	13.00	
38	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	13.00	
39	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	11.00	
40	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	11.00	

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1	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	0.48	
2	Pearl, BPA, near Wilsonville, OR	Transm./unattended	230.00		
3	Pelton, near Madras , OR	Transm./unattended	230.00	13.00	
4	Pelton, near Madras, OR	Transm./unattended	13.00	13.00	
5	Port Westward, near Clatskanie, OR	Transm./unattended	230.00	18.00	16.50
6	River Mill, near Estacada, OR	Transm./unattended	57.00	11.00	
7	Rivergate North Yard, near Portland, OR	Transm./unattended	230.00	115.00	13.00
8	Round Butte, near Madras, OR	Transm./unattended	500.00	230.00	12.50
9	Round Butte, near Madras, OR	Transm./unattended	230.00	12.50	
10	Round Butte, near Madras, OR	Transm./unattended	230.00	66.00	12.50
11	Sand Springs, 22 mi E/22 mi S of Bend, OR	Transm./unattended	500.00		
12	Sherwood, near Six Corners, OR	Transm./unattended	230.00	115.00	13.00
13	St. Marys, West Yard, near Beaverton, OR	Transm./unattended	230.00	115.00	13.00
14	Sullivan, West Linn, OR	Transm./Unattended	57.00	4.15	
15	Sycan, 27 mi S of Silver Lake, OR	Transm./unattended	500.00		
16	Trojan, near Rainier, OR	Transm./unattended	230.00	12.50	
17					
18	TOTAL MVa		26929.00	4798.18	374.62
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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
103	17		Capacitor Banks	3	15,600	1
17	1					2
22	1		Capacitor Banks	2	7,200	3
15	2					4
42	2		Capacitor Banks	2	7,200	5
20	1		Capacitor Banks	3	6,000	6
34	2		Capacitor Banks	2	3,600	7
34	2		Capacitor Banks	4	12,000	8
39	2		Capacitor Banks	4	14,400	9
56	2		Capacitor Banks	5	15,000	10
45	2		Capacitor Banks	2	7,200	11
24	2		Capacitor Banks	1	12,150	12
28	1		Capacitor Banks	2	6,000	13
39	4		Capacitor Banks	2	3,600	14
250	6					15
200	4		Capacitor Banks	8	28,800	16
56	2		Capacitor Banks	4	13,200	17
39	2		Capacitor Banks	2	7,200	18
						19
						20
37	2		Capacitor Banks	4	14,400	21
28	1		Capacitor Banks	2	6,000	22
28	1		Capacitor Banks	2	6,000	23
140	1					24
28	1		Capacitor Banks	2	6,000	25
28	1					26
17	1		Capacitor Banks	2	7,200	27
11	1					28
125	1					29
22	2		Capacitor Banks	4	6,000	30
22	1					31
7	1					32
56	2		Capacitor Banks	2	6,000	33
13	1		Capacitor Banks	3	9,000	34
14	1		Capacitor Banks	2	3,000	35
56	2		Capacitor Banks	4	12,600	36
140	2		Capacitor Banks	3	21,600	37
63	3		Capacitor Banks	1	8,400	38
63	3		Capacitor Banks	2	31,200	39
70	1		Capacitor Banks	1	24,000	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	1					1
17	1					2
32	2		Capacitor Banks	4	14,400	3
26	2		Capacitor Banks	2	3,600	4
25	1		Capacitor Banks	1	3,600	5
50	2		Capacitor Banks	2	6,600	6
						7
17	1		Capacitor Banks	2	6,000	8
22	1		Capacitor Banks	2	6,000	9
22	1		Capacitor Banks	2	6,000	10
50	2		Capacitor Banks	3	9,720	11
56	2		Capacitor Banks	4	12,000	12
33	1					13
13	1		Capacitor Banks	2	3,000	14
17	1		Capacitor Banks	2	7,200	15
41	2		Capacitor Banks	4	12,000	16
28	1		Capacitor Banks	2	7,200	17
7	1					18
34	2					19
28	1		Capacitor Banks	2	6,000	20
28	1		Capacitor Banks	2	6,000	21
45	2		Capacitor Banks	4	14,400	22
56	2		Capacitor Banks	4	12,600	23
125	3					24
56	2		Capacitor Banks	4	13,200	25
39	2		Capacitor Banks	2	7,200	26
50	2		Capacitor Banks	2	6,000	27
56	2		Capacitor Banks	3	10,800	28
45	2		Capacitor Banks	4	12,000	29
53	2		Capacitor Banks	4	7,200	30
56	2		Capacitor Banks	42	12,000	31
45	2		Capacitor Banks	2	6,000	32
50	2		Capacitor Banks	4	14,400	33
28	1		Capacitor Banks	2	6,000	34
17	1					35
10	1					36
10	1					37
50	2		Capacitor Banks	4	13,200	38
78	3		Capacitor Banks	6	20,400	39
28	1		Capacitor Banks	2	6,000	40

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
23	3					1
84	3		Capacitor Banks	6	19,200	2
50	2		Capacitor Banks	4	12,000	3
34	2		Capacitor Banks	3	10,800	4
17	1		Capacitor Banks	2	6,000	5
42	2		Capacitor Banks	4	9,000	6
20	1		Capacitor Banks	3	15,000	7
45	2		Capacitor Banks	2	3,600	8
39	2		Capacitor Banks	3	9,600	9
56	2		Capacitor Banks	3	10,800	10
45	2		Capacitor Banks	4	12,000	11
31	3		Capacitor Banks	3	15,000	12
20	1		Capacitor Banks	4	18,000	13
28	2					14
56	2		Capacitor Banks	4	14,400	15
						16
280	2					17
78	3		Capacitor Banks	6	18,600	18
15	2					19
34	2		Capacitor Banks	2	7,200	20
50	2		Capacitor Banks	4	12,000	21
27	1					22
15	1					23
19	1					24
35	1					25
28	1					26
50	2		Capacitor Banks	4	13,800	27
28	1		Capacitor Banks	2	6,600	28
17	1		Capacitor Banks	2	7,200	29
22	1					30
84	3		Capacitor Banks	6	18,000	31
						32
22	1		Capacitor Banks	2	7,200	33
22	1		Capacitor Banks	3	7,560	34
28	1		Capacitor Banks	2	6,000	35
78	3		Capacitor Banks	5	10,200	36
						37
28	1		Capacitor Banks	2	6,000	38
						39
15	2		Capacitor Banks	2	3,600	40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
45	2		Capacitor Banks	4	14,400	1
28	1		Capacitor Banks	2	6,000	2
						3
13	2		Capacitor Banks	1	10,800	4
140	1		Capacitor Banks	1	24,000	5
28	1		Capacitor Banks	2	6,000	6
17	1		Capacitor Banks	3	19,200	7
33	3		Capacitor Banks	3	4,770	8
50	2		Capacitor Banks	4	12,000	9
56	2		Capacitor Banks	5	36,000	10
						11
			Capacitor Banks	1	24,000	12
						13
24	2		Capacitor Banks	2	7,200	14
56	2		Capacitor Banks	4	12,000	15
14	1					16
100	2		Capacitor Banks	2	16,800	17
25	6					18
50	2		Capacitor Banks	5	36,000	19
8	1					20
6	1					21
278	6		Capacitor Banks	12	60,000	22
50	2		Capacitor Banks	4	12,000	23
22	1		Capacitor Banks	2	6,000	24
22	1		Capacitor Banks	2	6,000	25
						26
56	2		Capacitor Banks	4	12,000	27
39	2		Capacitor Banks	4	7,200	28
56	2		Capacitor Banks	2	7,200	29
56	2		Capacitor Banks	4	13,200	30
28	1		Capacitor Banks	3	19,200	31
22	1		Capacitor Banks	2	7,200	32
112	4		Capacitor Banks	7	44,400	33
41	2		Capacitor Banks	2	6,000	34
6	1		Capacitor Banks	1	12,000	35
18	2		Capacitor Banks	2	6,600	36
			Capacitor Banks	1	24,000	37
56	2		Capacitor Banks	4	13,200	38
28	1		Capacitor Banks	3	15,200	39
24	2		Capacitor Banks	3	7,800	40

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
104	4		Capacitor Banks	6	18,000	2
42	2		Capacitor Banks	4	13,200	3
15	2		Capacitor Banks	1	1,800	4
						5
						6
						7
						8
464	4					9
170	1					10
502	2					11
140	1					12
28	1		Capacitor Banks	2	6,000	13
320	2					14
320	1					15
28	1		Capacitor Banks	2	6,000	16
685	3					17
55	1					18
55	1					19
80	3					20
640	2					21
56	2		Capacitor Banks	4	12,000	22
164	3					23
100	2					24
300	3					25
140	1					26
32	2					27
27	1					28
			Series Capacitor	1	363,000	29
572	2					30
						31
168	1					32
			Reactors	3	180,000	33
640	2					34
125	1					35
320	1					36
53	3	1				37
8	1					38
64	2					39
2	1					40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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.
1	2					1
						2
164	4					3
3	1					4
450	3					5
32	2					6
520	4		Capacitor Banks	2	43,500	7
561	3		Reactors	12	180,000	8
372	3	2				9
22	1					10
			Series Capacitor	1	546,000	11
640	2					12
960	3		Capacitor Banks	3	108,000	13
33	1					14
			Series Capacitor	1	546,000	15
56	2					16
						17
16913	366	3		435	3,402,500	18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426 Line No.: 19 Column: a

Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulation equipment.

Schedule Page: 426 Line No.: 20 Column: a

Footnote Linked. See note on 426, Row: 19, col/item:

Schedule Page: 426.1 Line No.: 7 Column: a

Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.

Schedule Page: 426.2 Line No.: 16 Column: a

Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.

Schedule Page: 426.2 Line No.: 32 Column: a

Switching only.

Schedule Page: 426.2 Line No.: 37 Column: a

Switching only.

Schedule Page: 426.2 Line No.: 39 Column: a

Switching only.

Schedule Page: 426.3 Line No.: 3 Column: a

Switching only. Distribution owned by CRPUD.

Schedule Page: 426.3 Line No.: 11 Column: a

Regulating only.

Schedule Page: 426.3 Line No.: 12 Column: a

Switching only. Distribution owned by CRPUD.

Schedule Page: 426.3 Line No.: 13 Column: a

Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.

Schedule Page: 426.3 Line No.: 26 Column: a

Switching only.

Schedule Page: 426.3 Line No.: 37 Column: a

Switching only.

Schedule Page: 426.4 Line No.: 8 Column: a

Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which Respondent owns switching and/or regulating equipment.

Schedule Page: 426.4 Line No.: 17 Column: a

Jointly owned with Idaho Power Company, Power Resources Cooperative and BA Leasing BCS, LLC. PGE has a 65% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 18 Column: a

Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing BCS, LLC. PGE has a 65% share of the jointly owned capacity, 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 19 Column: a

Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing BCS, LLC. PGE has a 65% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 20 Column: a

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 20% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 23 Column: a

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 20% share of jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 24 Column: a

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and

Avista Corporation.   PGE has a 20% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 29 Column: a

Line compensation only.

Schedule Page: 426.4 Line No.: 31 Column: a

Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.

Schedule Page: 426.4 Line No.: 33 Column: a

Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.

Schedule Page: 426.5 Line No.: 2 Column: a

Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.

Schedule Page: 426.5 Line No.: 3 Column: a

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 66.67% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 4 Column: a

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 66.67% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 9 Column: a

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 66.67% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 10 Column: a

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 66.67% share of the jointly owned capacity, 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 11 Column: a

Line compensation only.

Schedule Page: 426.5 Line No.: 15 Column: a

Line compensation only.

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Schedule	Page No.