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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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 2010/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 2010/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*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(503) 464-7121	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Maria M. Pope	Maria M. Pope	05/30/2012
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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	Not Applicable
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	Not Applicable
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	None
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

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	Transmission Lines Added During the Year	424-425	
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	
70	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Schedule Page: 2 Line No.: 62 Column:

Updated 5/30/12. See Footnotes for this page for explanation of changes.

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) ☒ No

CONTROL OVER RESPONDENT

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	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	
17				
18	SunWay 3, 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.

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

SunWay 3, 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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President and Chief Executive Officer	James J. Piro	561,137
2	Senior Vice President, Finance, Chief Financial	Maria M. Pope	422,147
3	Officer, and Treasurer		
4	Vice President, Nuclear and Power Supply/Generation	Stephen M. Quennoz	264,753
5	Vice President, General Counsel and Corporate	J. Jeffrey Dudley	255,324
6	Compliance Officer		
7	Vice President, Power Operations and	James F. Lobdell	253,213
8	Resource Strategy		
9	Senior Vice President, Customer Service,	Stephen R. Hawke	248,402
10	Transmission and Delivery		
11	Vice President, Administration	Arleen N. Barnett	242,232
12	Vice President, Customers and Economic Development	Carol A. Dillin	226,100
13	Vice President, Distribution Operations	William O. Nicholson	215,631
14	Vice President, Information Technology and	Campbell A. Henderson	206,360
15	Chief Information Officer		
16	Vice President, Distribution Services	O. Bruce Carpenter	186,065
17	Vice President, Public Policy	W. David Robertson	182,762
18	Vice President, Transmission	Joe A. McArthur	106,280
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Schedule Page: 104 Line No.: 1 Column: c

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

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

Retired from position effective July 1, 2010.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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, Jr.	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	President and Chief Executive Officer 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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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2010/Q4

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

Does the respondent have formula rates?

☐ Yes

☒ No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[ ] Yes [X] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

1. None

2. None

3. None

4. None

5. None

6. 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 (OPUC) 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.

On March 11, 2010, PGE remarketed $121 million of Pollution Control Bonds due May 2033 at 5.0%; such bonds are backed by first mortgage bonds issued by the Company.

On June 15, 2010, PGE issued $58 million of 3.81% Series First Mortgage Bonds due June 15, 2017, as authorized by the OPUC 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.

During 2010, PGE issued and repaid short-term debt, the outstanding balance of which was $19 million 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 2013. See Page 123, Notes to Financial Statements, Note 8 - Revolving Credit Facilities, for further information.

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, 2010, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the Comparative Balance Sheet with respect to these indemnities.

7. None

8. None

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 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, 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 Utility Reform Project (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 did 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.

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 Settlement allowed PGE to remove from its balance sheet the remaining investment in Trojan of approximately $180 million at September 30, 2000, along with several largely offsetting regulatory liabilities. 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, 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. Following various appeals and proceedings, the Oregon Court of Appeals issued an opinion in October 2007 that reversed the Settlement Order and remanded the Settlement Order to the OPUC for reconsideration.

As a result of its reconsideration of the Settlement Order, the OPUC issued an order on September 30, 2008 that required 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 OPUC order to the Oregon Court of Appeals. A decision by the Oregon Court of Appeals remains pending.

The Company completed the distribution of the refund to customers, plus accrued interest, as required by the September 30, 2008 OPUC order.

Management cannot predict the ultimate outcome of these matters. Management believes, however, 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 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 charged 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. On February 10, 2009, the Circuit Court judge denied the plaintiff's motion to lift the abatement.

Management cannot predict the ultimate outcome of these matters. Management believes, however, 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 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 were filed with the court and on April 9, 2009, the Ninth Circuit issued an order that denied the requests for rehearing. On April 16, 2009, the Ninth Circuit 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 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. As of the filing date of this report, the FERC has not issued an order in response to the Ninth Circuit remand.

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 resolved the claims 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 did 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, however, 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 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 September 30, 2008, the plaintiffs filed a complaint against PGE for alleged violations of the federal Clean Air Act (CAA), Oregon's Regional Haze State Implementation Plan (SIP) at PGE's Boardman Coal Plant, the Plant's CAA Title V permit, 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.

On September 30, 2009, the District Court ruled on PGE's motion to dismiss most of the claims. In summary, the court denied PGE's motion with respect to most of the plaintiff's claims, but did grant PGE's motion with respect to certain of the plaintiff's claims. The principal claims that remain are (i) that PGE constructed Boardman without complying with the 1974 and 1977 federal pre-construction permitting requirements, (ii) that PGE modified Boardman in the 1990s without complying with Oregon's pre-construction permitting requirements, and (iii) that certain modifications to Boardman triggered new source performance standards (NSPS). Discovery in the case continues, with a tentative trial date set for August 2011.

Management cannot predict the ultimate outcome of this matter. Management believes, however, that it has strong defenses to the plaintiffs' claims and intends to vigorously defend against this lawsuit.

United States Environmental Protection Agency, Region 10 - Notice of Violation

On September 28, 2010, the United States Environmental Protection Agency (EPA) issued a Notice of Violation (NOV) to PGE in accordance with the CAA. The NOV states that the EPA has determined that the Company is violating the NSPS under Section 111 of the CAA, 42 U.S.C. Section 7411 *et seq.*, and Operating Permit requirements under Title V of the CAA, 42 U.S.C. Sections 7661 *et seq.*, at the Boardman plant. In the NOV, the EPA asserts that certain projects at the Boardman plant completed in 1998 and in 2004 triggered the NSPS, that PGE did not meet the emissions standards required by the regulations and that, therefore, PGE has operated the boiler at the Boardman plant in violation of the CAA. The NOV states the maximum civil penalties the EPA is authorized to impose under the CAA for violations of the NSPS (which range from $25,000 to $37,500 per day), but does not impose any penalties, or specify the amount of any proposed penalties with respect to the alleged violations. Accordingly, management cannot estimate the range of potential liability for the violations asserted in the NOV. In the NOV, the EPA has offered PGE an opportunity to confer about the violations cited and to present information on the specific findings of the EPA. PGE expects to meet with the EPA during the first quarter of 2011.

Management cannot predict the outcome of the claims asserted by the EPA in the NOV. Management believes, however, that it has strong defenses to these claims and intends to vigorously defend against them.

10. None

11. (Reserved)

12. None

13. Effective July 1, 2010, Joe A. McArthur retired as Vice President, Transmission.

14. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2010/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	6,273,112,149	5,594,743,122
3	Construction Work in Progress (107)	200-201	124,966,713	406,591,842
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,398,078,862	6,001,334,964
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,858,431,769	2,684,786,163
6	Net Utility Plant (Enter Total of line 4 less 5)		3,539,647,093	3,316,548,801
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)		3,539,647,093	3,316,548,801
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		27,062,796	27,051,143
19	(Less) Accum. Prov. for Depr. and Amort. (122)		11,762,022	11,141,302
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	2,490,770	-298,974
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)		0	61
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		79,153,262	98,151,883
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		3,083,458	1,768,677
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		100,028,264	115,531,488
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		3,810,683	12,534,498
36	Special Deposits (132-134)		83,203,795	57,454,600
37	Working Fund (135)		30,313	30,802
38	Temporary Cash Investments (136)		0	18,000,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		116,838,849	141,570,577
41	Other Accounts Receivable (143)		21,338,795	22,067,161
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,967,320	5,199,357
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		602,865	349,024
45	Fuel Stock (151)	227	21,503,107	23,897,315
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	30,786,477	31,433,083
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	6,081	11,357
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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2010/Q4

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	2,944,884	3,051,673
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)		70,070,070	93,677,728
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)		92,802,931	95,399,244
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		15,546,066	12,329,416
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		3,083,458	1,768,677
65	Derivative Instrument Assets - Hedges (176)		112,663	182,717
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		451,906,801	505,381,161
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		13,502,264	14,510,469
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	3,368,428	0
72	Other Regulatory Assets (182.3)	232	755,788,489	654,999,079
73	Prelim. Survey and Investigation Charges (Electric) (183)		12,865,561	4,807,442
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)		66,543	99,737
77	Temporary Facilities (185)		1,706	-1,401
78	Miscellaneous Deferred Debits (186)	233	12,829,644	10,195,597
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)		23,243,577	25,741,617
82	Accumulated Deferred Income Taxes (190)	234	407,943,476	304,550,743
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,229,609,688	1,014,903,283
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,321,191,846	4,952,364,733

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	end of 2010/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	823,989,481	821,983,367
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	15,302,074
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	8,034,721
11	Retained Earnings (215, 215.1, 216)	118-119	767,164,180	720,413,968
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-616,911	-991,261
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)	-5,340,299	-5,532,427
16	Total Proprietary Capital (lines 2 through 15)		1,592,463,804	1,543,141,000
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,809,000,000	1,596,500,000
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	113,786	149,383,985
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,318,880	1,558,570
24	Total Long-Term Debt (lines 18 through 23)		1,807,794,906	1,744,325,415
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)		8,177,406	5,590,393
29	Accumulated Provision for Pensions and Benefits (228.3)		241,043,851	244,007,688
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		10,762,646	37,824,781
32	Long-Term Portion of Derivative Instrument Liabilities		188,185,649	127,111,674
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		63,796,273	63,206,492
35	Total Other Noncurrent Liabilities (lines 26 through 34)		511,965,825	477,741,028
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		18,999,088	0
38	Accounts Payable (232)		162,840,577	180,924,525
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		406,624	-131,899
41	Customer Deposits (235)		6,400,962	5,535,629
42	Taxes Accrued (236)	262-263	12,636,141	9,246,634
43	Interest Accrued (237)		25,810,201	26,913,692
44	Dividends Declared (238)		20,158,740	19,818,207
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) [ ] An Original (2) [X] A Resubmission	05/30/2012	end of 2010/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)		10,855,769	11,522,387
48	Miscellaneous Current and Accrued Liabilities (242)		12,087,549	15,993,611
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		376,162,423	255,446,757
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		188,185,649	127,111,674
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		458,172,425	398,157,869
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		31,959	31,959
57	Accumulated Deferred Investment Tax Credits (255)	266-267	14,052	61,995
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	1,252,029	2,595,667
60	Other Regulatory Liabilities (254)	278	92,510,469	106,446,062
61	Unamortized Gain on Reaquired Debt (257)		98,637	108,862
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		519,679,362	404,960,313
64	Accum. Deferred Income Taxes-Other (283)		337,208,378	274,794,563
65	Total Deferred Credits (lines 56 through 64)		950,794,886	788,999,421
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,321,191,846	4,952,364,733

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	1,935,745,889	1,965,977,746		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,243,610,554	1,345,165,109		
5	Maintenance Expenses (402)	320-323	98,971,908	95,125,269		
6	Depreciation Expense (403)	336-337	208,952,082	184,241,239		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	272,063	53,948		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	17,223,182	15,718,809		
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)		4,869,775	8,221,953		
13	(Less) Regulatory Credits (407.4)		2,688,590	7,862,322		
14	Taxes Other Than Income Taxes (408.1)	262-263	89,639,509	84,247,655		
15	Income Taxes - Federal (409.1)	262-263	-20,267,757	-46,503,818		
16	- Other (409.1)	262-263	125,385	-472,910		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	250,778,481	194,668,799		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	181,110,741	104,229,998		
19	Investment Tax Credit Adj. - Net (411.4)	266		-1,456,233		
20	(Less) Gains from Disp. of Utility Plant (411.6)		115,084	67,840		
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)		745,800	534,666		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,715,652,567	1,772,030,326		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		220,093,322	193,947,420		

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
1,935,745,889	1,965,977,746					2
						3
1,243,610,554	1,345,165,109					4
98,971,908	95,125,269					5
208,952,082	184,241,239					6
272,063	53,948					7
17,223,182	15,718,809					8
						9
4,646,000	4,646,000					10
						11
4,869,775	8,221,953					12
2,688,590	7,862,322					13
89,639,509	84,247,655					14
-20,267,757	-46,503,818					15
125,385	-472,910					16
250,778,481	194,668,799					17
181,110,741	104,229,998					18
	-1,456,233					19
115,084	67,840					20
						21
						22
						23
745,800	534,666					24
1,715,652,567	1,772,030,326					25
220,093,322	193,947,420					26

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)		220,093,322	193,947,420		
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)		189,506	342,084		
33	Revenues From Nonutility Operations (417)		5,543,676	4,536,407		
34	(Less) Expenses of Nonutility Operations (417.1)		4,809,942	4,462,666		
35	Nonoperating Rental Income (418)		1,955,204	1,530,497		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	374,350	321,180		
37	Interest and Dividend Income (419)		142,915	535,216		
38	Allowance for Other Funds Used During Construction (419.1)		13,224,534	17,586,528		
39	Miscellaneous Nonoperating Income (421)		4,567,953	7,699,709		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		20,809,184	27,404,787		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		33,720	36,228		
45	Donations (426.1)		1,252,967	2,192,459		
46	Life Insurance (426.2)		-1,669,582	-2,251,603		
47	Penalties (426.3)		-125,151	-90,923		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		751,988	992,168		
49	Other Deductions (426.5)		1,150,981	26,457,109		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,394,923	27,335,438		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,068,509	1,043,696		
53	Income Taxes-Federal (409.2)	262-263	-299,085	603,005		
54	Income Taxes-Other (409.2)	262-263	25,743	137,614		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	4,990,809	4,913,440		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,532,135	11,252,118		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		47,943	418,483		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		4,205,898	-4,972,846		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		15,208,363	5,042,195		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		105,459,321	97,557,599		
63	Amort. of Debt Disc. and Expense (428)		2,528,412	2,580,517		
64	Amortization of Loss on Reaquired Debt (428.1)		2,498,040	2,498,040		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		10,225	31,474		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		8,678,985	12,835,105		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		9,096,795	11,816,045		
70	Net Interest Charges (Total of lines 62 thru 69)		110,057,738	103,623,742		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		125,243,947	95,365,873		
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)		125,243,947	95,365,873		

Name of Respondent Portland General Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/30/2012	Year/Period of Report End of 2010/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		716,561,173	697,429,893
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)		124,869,597	95,044,693
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		-78,119,385	(76,363,413)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-78,119,385	(76,363,413)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			450,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		763,311,385	716,561,173
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		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)		767,164,180	720,413,968
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-991,261	(862,441)
50	Equity in Earnings for Year (Credit) (Account 418.1)		374,350	321,180
51	(Less) Dividends Received (Debit)			450,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		-616,911	(991,261)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2010/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)	125,243,947	95,365,873
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	226,447,327	200,013,996
5	Amortization of Debt Discount	5,016,227	5,047,083
6	Amortization of Unrecovered Plant	4,646,000	4,646,000
7	Net Asset from Price Risk Management	117,569,070	-144,125,217
8	Deferred Income Taxes (Net)	73,126,414	84,100,123
9	Investment Tax Credit Adjustment (Net)	-47,943	-1,874,716
10	Net (Increase) Decrease in Receivables	45,433,500	-52,765,961
11	Net (Increase) Decrease in Inventory	3,152,879	12,345,457
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-10,721,852	-13,438,634
14	Net (Increase) Decrease in Other Regulatory Assets	-90,613,542	125,875,020
15	Net Increase (Decrease) in Other Regulatory Liabilities	-32,554,780	-50,660,061
16	(Less) Allowance for Other Funds Used During Construction	13,224,534	17,586,528
17	(Less) Undistributed Earnings from Subsidiary Companies	374,350	321,180
18	Contribution to Pension Plan	-30,000,000	7,974,052
19	Other: Margin Deposit (Account 134)	-25,896,362	130,947,003
20	Other Operating	-2,872,807	-771,754
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	394,329,194	384,770,556
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-450,386,736	-712,469,168
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-11,653	-27,808
30	(Less) Allowance for Other Funds Used During Construction	-13,224,534	-17,586,528
31	Other (provide details in footnote):		
32			
33	Other Capital Activities	-3,572,230	901,270
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-440,746,085	-694,009,178
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	-2,415,395	-31,400
40	Contributions and Advances from Assoc. and Subsidiary Companies		450,000
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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	-3,697,399	-5,713,802
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	-45,814,740	-35,684,997
54	Sales of Trojan Decommissioning Trust Securities	49,959,991	36,046,346
55	Distribution from Trust Fund - Boardman Deferral	18,726,448	
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-423,987,180	-698,943,031
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	249,400,000	580,000,000
62	Preferred Stock		
63	Common Stock		175,932,749
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	18,999,088	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	268,399,088	755,932,749
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-186,170,199	-142,301,427
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	-1,770,431	-4,718,268
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-77,524,776	-72,071,232
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	2,933,682	334,862,244
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-26,724,304	20,689,769
87			
88	Cash and Cash Equivalents at Beginning of Period	30,565,300	9,875,531
89			
90	Cash and Cash Equivalents at End of period	3,840,996	30,565,300

Schedule Page: 120   Line No.: 55   Column: b

On February 12, 2010, the OPUC issued an order (Order No. 10-051) authorizing the offset of the Boardman power cost deferral with the simultaneous amortization of an equal amount of customer credits related to nuclear decommissioning activities. Based on the OPUC order, $18,726,448 was transferred from the Nuclear decommissioning trust to PGE.

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 Comparative Balance Sheet:

	Balance at Beginning of Year	Balance at End of Year
Cash (131)	$ 12,534,498	$ 3,810,683
Working Funds (135)	30,802	30,313
Temporary Cash Investment (136)	18,000,000	-
	$ 30,565,300	$ 3,840,996

Cash paid during the year:	2009	2010
Interest	$ 86,143,996	$ 106,609,092
AFDC - Borrowed	(11,816,045)	(9,096,795)
	$ 74,327,951	$ 97,512,297
Income taxes	$ 1,948,824	$ 100,200

NOTE 1: BASIS OF PRESENTATION

Nature of Operations

Portland General Electric Company (PGE or the Company) 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, 2010, PGE served 820,676 retail customers with a service area population of approximately 1.7 million, comprising approximately 44% of the state’s population.

As of December 31, 2010, PGE had 2,671 employees, with 872 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 837 and 35 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 accounting principles generally accepted in the United States of America (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 $18 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 potential gain contingencies or 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.

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 none as of December 31, 2010 and $18 million as of December 31, 2009.

Accounts Receivable

Accounts receivable are recorded at invoiced amounts and do not bear interest when recorded. A late fee 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 general expenses, 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 $83 million and $56 million as of December 31, 2010 and 2009, 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 an OPUC order received in January 2010, PGE was ordered 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 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 8% in 2010 and 7% in 2009. AFDC from borrowed funds was $9 million in 2010 and $12 million in 2009 and is reflected in the statements of income as a reduction to interest expense. AFDC from equity funds was $13 million in 2010 and $18 million in 2009 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 3.9% in 2010 and 3.8% in 2009. Estimated asset retirement removal costs included in depreciation expense approximated $47 million in both 2010 and 2009.

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 September 13, 2010, PGE received an order from the OPUC authorizing new depreciation rates to be effective January 2011. The average lives below reflect depreciation lives effective in 2010.

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	89 years
Wind	27 years
Transmission	48 years
Distribution	39 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.

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. Accumulated amortization was $133 million and $122 million as of December 31, 2010 and 2009, respectively, with amortization expense of $17 million in 2010 and $16 million in 2009. Future estimated amortization expense as of December 31, 2010 is as follows: $17 million in 2011, $14 million in 2012, $8 million in 2013, $5 million in 2014 and $4 million in 2015.

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, for future ratemaking. 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 (i) probable future revenue associated with certain costs that are expected to be recovered from customers through the ratemaking process, or (ii) probable future collections from customers resulting from revenue accrued for completed alternative revenue programs, provided certain criteria are met. 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 prices are established by or subject to approval by independent third-party regulators; prices are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Once the regulatory asset or liability is reflected in prices, 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 prices.

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 prices 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.

For additional information concerning the Company's regulatory assets and liabilities, see Note 6, 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 a fixed 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 regulated 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 regulated ROE for that year being no greater than 1% below the Company's last authorized ROE. PGE's authorized ROE was 10.0% for both 2010 and 2009. 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 2010, the deadband ranged from $17 million below to $35 million above the baseline. Although PGE's actual NVPC as determined pursuant to the PCAM for 2010 was below the baseline by $12 million, it was within the established deadband and, accordingly, no customer refund was recorded in 2010. A final determination regarding the 2010 PCAM results will be made by the OPUC through a public filing and review in 2011.

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 was made by the OPUC through a public filing and review in 2010, which concluded that no customer collection was warranted for 2009.

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 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 as of the financial statement date and the amount of the loss can be reasonably estimated. If a range of probable loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. Legal costs incurred in connection with loss contingencies are expensed as incurred.

If a probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed and the disclosure includes a statement to that effect. A material loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred.

If an asset has been impaired or a liability incurred after the financial statement date, but prior to the issuance of the financial statements, the loss contingency is disclosed, if material, and the amount of any estimated loss is recorded in the subsequent reporting period.

Gain contingencies are recognized when realized and are disclosed when material.

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, 2010 and 2009.

Revenue Recognition

Revenues are recognized as electricity is delivered to customers and include amounts for any services provided. The prices 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 $39 million in 2010 and $38 million in 2009.

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 accrues revenue to be billed to customers in future periods or defers the recognition of certain revenues to 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 prices and are charged or credited directly to a regulatory asset or regulatory liability. These amounts were recognized as net regulatory assets of $95 million and $91 million as of December 31, 2010 and 2009, respectively, and will be included in prices 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.

Unrecognized tax benefits 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 no longer considered uncertain, 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.

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.

Recent Accounting Pronouncement

Accounting Standards Update (ASU) 2010-06, *Fair Value Measurements and Disclosures (Topic 820) - Improving Disclosures about Fair Value Measurement* (ASU 2010-06) requires (i) new disclosures about the transfers in and out of fair value measurement Levels 1 and 2 and a description of the reasons for the transfers and (ii) separate reporting about purchases, sales, issuances, and settlements for Level 3 fair value measurements. For additional information on the three broad levels, see Note 4, Fair Value of Financial Instruments. ASU 2010-06 also clarifies existing disclosures and requires (i) an entity to provide fair value measurement disclosures for each class of assets and liabilities and (ii) disclosures about inputs and valuation techniques. In accordance with the provisions of ASU 2010-06, on January 1, 2010, PGE adopted the requirements of ASU 2010-06, except for the disclosures about purchases, sales, issuances and settlements in the roll forward of activity of Level 3 fair value measurements, which did not have a material impact on PGE’s financial position, results of operations, or cash flows. Based on the provisions of ASU 2010-06, PGE will adopt the disclosures requirements about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements on January 1, 2011, which is not expected to have a material impact on PGE’s financial position, results of operations, or cash flows.

NOTE 3: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

The following is the activity in the Accumulated Provision for Uncollectible Accounts (Account 144), in millions:

	Years Ended December 31, 2010	Years Ended December 31, 2009
Balance as of beginning of year	$ 5	$ 4
Increase in provision	7	9
Amounts written off, less recoveries	(7)	(8)
Balance as of end of year	$ 5	$ 5

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	
	2010	2009	2010	2009
Cash equivalents	$ 13	$ 31	$ —	$ —
Marketable securities, at fair value:				
Equity securities	—	—	19	21
Debt securities	21	19	2	4
Insurance contracts, at cash surrender value	—	—	23	22
Total	$ 34	$ 50	$ 44	$ 47

Other Current Assets and Other Current Liabilities

Other current assets and other current liabilities consist of the following (in millions):

	As of December 31,	
	2010	**2009**
Other current assets:		
Income taxes receivable	$ 22	$ 56
Other	45	38
Total other current assets	$ 67	$ 94
Other current liabilities:		
Accrued interest payable	$ 26	$ 27
Other	52	65
Total other current liabilities	$ 78	$ 92

Other Assets

The Company incurs preliminary engineering costs related to potential future capital projects, which are capitalized in Other noncurrent assets in the balance sheets. Preliminary engineering costs consist of expenditures for preliminary surveys, plans, and investigations made for the purpose of determining the feasibility of utility projects being considered. Once the project is approved for construction, such costs are reclassified to Electric utility plant. If the project is abandoned, such costs are expensed to Production and distribution expense in the period such determination is made. If any preliminary engineering costs are expensed, the Company may seek recovery of such costs in customer prices, although there can be no guarantee such recovery would be granted. As of December 31, 2010 and 2009, PGE has recorded preliminary engineering costs of $13 million and $5 million, respectively. For the years ended December 31, 2010 and 2009, PGE did not expense any material preliminary engineering costs.

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, 2010 and 2009:

- 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, 2010, the estimated aggregate fair value of PGE’s long-term debt was $1,968 million, compared to its $1,808 million carrying amount. 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.

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 values were recognized at fair value are as follows by level within the fair value hierarchy (in millions):

	As of December 31, 2010			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Nuclear decommissioning trust (1):				
Money market funds	$ —	$ 13	$ —	$ 13
Debt securities:				
U.S. treasury securities	3	—	—	3
Corporate debt securities	—	6	—	6
Mortgage-backed securities	—	7	—	7
Municipal securities	—	4	—	4
Asset-backed securities	—	1	—	1
Non-qualified benefit plan trust (2):				
Equity securities:				
Mutual funds	16	1	—	17
Common stocks	2	—	—	2
Debt securities - mutual funds	2	—	—	2
Assets from price risk management activities (1) (3):				
Electricity	—	4	1	5
Natural gas	—	11	—	11
	$ 23	$ 47	$ 1	$ 71
Liabilities - Liabilities from price risk management activities (1) (3):				
Electricity	$ —	$ 102	$ 17	$ 119
Natural gas	—	153	104	257
	$ —	$ 255	$ 121	$ 376

(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.
(2) Excludes insurance policies which are recorded at cash surrender value.
(3) For further information, see Note 5, Price Risk Management.

	As of December 31, 2009			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Nuclear decommissioning trust (1):				
Money market funds	$ —	$ 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 (2):				
Equity securities:				
Mutual funds	19	—	—	19
Common stocks	2	—	—	2
Debt securities - mutual funds	4	—	—	4
Assets from price risk management activities (1) (3):				
Electricity	—	7	—	7
Natural gas	—	6	—	6
	$ 29	$ 59	$ —	$ 88
Liabilities - Liabilities from price risk management activities (1) (3):				
Electricity	$ —	$ 72	$ 9	$ 81
Natural gas	—	29	145	174
	$ —	$ 101	$ 154	$ 255

(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.
(2) Excludes insurance policies which are recorded at cash surrender value.
(3) For further information, see Note 5, Price Risk Management.

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. During the year ended December 31, 2010, PGE determined that the money market funds held by the Nuclear decommissioning trust should be classified as Level 2 rather than Level 1, as such investments do not have an active market for the identical assets. Accordingly, the Company corrected the classification of money market funds from Level 1 to Level 2 in the above table as of December 31, 2009.

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.

Assets and liabilities from price risk management activities represent derivative transactions entered into by PGE to manage its exposure to commodity price risk, foreign exchange rate risk, mitigate the effects of market fluctuations, and minimize net power costs for service to the Company's retail customers. These transactions 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 considers 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 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, 2010	2009
Liabilities from price risk management activities, net as of beginning of year	$ (154)	$ (123)
Net realized and unrealized losses	(65)	(47)
Purchases, issuances, and settlements, net	(27)	—
Net transfers out of Level 3	126	16
Liabilities from price risk management activities, net as of end of year	$ (120)	$ (154)
Level 3 net realized and unrealized losses that have been fully offset by the effect of regulatory accounting	$ (95)	$ (49)

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. Transfers out of Level 3 occur when the significant inputs become more observable, such as the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers in and transfers out of Level 3 at the end of the reporting period for all of its financial instruments.

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 fuel and 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. In accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer the gains and losses from derivative activity until realized. This accounting treatment defers the mark-to-market gains and losses on derivative activities until settlement, reducing volatility related to commodity price risk 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, 2010 and 2009, the Company had $31 million and $28 million, respectively, in collateral posted with these counterparties, consisting entirely of letters of credit.

PGE's net volumes related to its Assets and Liabilities from price risk management activities resulting from its derivative transactions, which are expected to deliver or settle at various dates through 2014, were as follows (in millions):

	As of December 31,					
	2010			2009		
Commodity:						
Electricity		9	MWh		12	MWh
Natural gas		93	Decatherms		96	Decatherms
Foreign currency exchange	$	7	Canadian	$	5	Canadian

The fair values of PGE's Assets and Liabilities from price risk management activities consist of the following (in millions):

	As of December 31,	
	2010	**2009**
Current assets:		
Commodity contracts:		
Electricity	$ 4	$ 6
Natural gas	9	5
Total current derivative assets	13 (1)	11 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	1	1
Natural gas	2	1
Total noncurrent derivative assets	3 (2)	2 (2)
Total derivative assets not designated as hedging instruments	$ 16	$ 13
Total derivative assets	$ 16	$ 13
Current liabilities:		
Commodity contracts:		
Electricity	$ 77	$ 57
Natural gas	111	71
Total current derivative liabilities	188	128
Noncurrent liabilities:		
Commodity contracts:		
Electricity	42	24
Natural gas	146	103
Total noncurrent derivative liabilities	188	127
Total derivative liabilities not designated as hedging instruments	$ 376	$ 255
Total derivative liabilities	$ 376	$ 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 not designated as hedging instruments are classified in Purchased Power in the statements of income and were as follows (in millions):

	Years Ended December 31,	
	2010	**2009**
Commodity contracts:		
Electricity	$ 127	$ 79
Natural Gas	192	101

Unrealized gains and losses and certain realized gains and losses presented in the table above are offset within the statement of income by the effects of regulatory accounting. Of the net loss recognized in net income for the years ended December 31, 2010 and 2009, $258 million and $98 million, respectively, have 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, 2010 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2011	2012	2013	2014	Total
Commodity contracts:					
Electricity	$ 73	$ 25	$ 11	$ 5	$ 114
Natural gas	102	92	43	9	246
Net unrealized loss	$ 175	$ 117	$ 54	$ 14	$ 360

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, 2010 was $314 million, for which the Company had $180 million in posted collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2010, the cash requirement to either post as collateral or settle the instruments immediately would have been $302 million.

Counterparties representing 10% or more of Assets and Liabilities from price risk management activities were as follows:

	As of December 31,	
	2010	2009
Assets from price risk management activities:		
Counterparty A	23%	41%
Counterparty B	22	14
Counterparty C	1	15
Counterparty F	11	2
Counterparty E	10	2
	67%	74%
Liabilities from price risk management activities:		
Counterparty A	24%	19%
Counterparty C	12	13
Counterparty D	9	14
	45%	46%

For additional information concerning the determination of fair value for the Company's Assets and Liabilities from price risk management activities, see Note 4, Fair Value of Financial Instruments.

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 (dollars in millions):

	Weighted Average Remaining Life	As of December 31, 2010	2009
Regulatory assets:			
Price risk management (1)	2 years	$ 360	$ 243
Pension and other postretirement plans (1)	(2)	213	196
Deferred income taxes (1)	(3)	112	108
Deferred broker settlements (1)	1 year	24	50
Renewable energy deferral	1 year	22	—
Boardman power cost deferral		—	17
Regulatory treatment of income taxes (SB 408)	(4)	1	7
Other (5)	Various	24	34
Total regulatory assets		$ 756	$ 655
Regulatory liabilities:			
Asset retirement obligations (6)	(3)	$ 33	$ 30
Trojan ISFSI pollution control tax credits	(7)	22	17
Power Cost Adjustment Mechanism		—	1
Other	Various	38	58
Total regulatory liabilities		$ 93	$ 106

(1) Does not include a return on investment.
(2) Recovery expected over the average service life of employees. For additional information, see Note 2, Summary of Significant Accounting Policies.
(3) Recovery expected over the estimated lives of the assets.
(4) Collection period not yet determined.
(5) Of the total other unamortized regulatory asset balances, a return is recorded on $25 million and $22 million as of December 31, 2010 and 2009, respectively.
(6) Included in rate base for ratemaking purposes.
(7) The refund period for the $4 million noncurrent portion of the Trojan ISFSI pollution control tax credits has not yet been determined.

As of December 31, 2010, PGE had regulatory assets of $48 million earning a return on investment at the following rates: (1) $23 million at PGE’s authorized cost of capital, 8.284% through 2010; (2) $14 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) $11 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. For further information, see Note 5, Price Risk Management.

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. For further information, see Note 10, Employee Benefits.

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. For further information, see Note 11, Income Taxes.

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.

Renewable energy deferral reflects the accrued net revenue requirement related to new renewable resources and associated transmission that are not yet included in customer prices, with the majority related to the placing in service of the Biglow Canyon Wind Farm. Recovery of net revenue requirements associated with new renewable resources, which are required by the 2007 Oregon Renewable Energy Act, is allowed under a renewable adjustment clause mechanism authorized by the OPUC.

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. On February 12, 2010, the OPUC issued an order reducing the amount to be recovered from customers by $18 million; such reduction was charged to Purchased power and fuel expense in the fourth quarter of 2009. Pursuant to the order, collection of the remaining deferred balance was offset in the first quarter of 2010 with certain credits then owed to customers related to accrued savings on decommissioning activities at PGE's closed Trojan Nuclear Plant.

Asset retirement removal costs represent the costs that do not qualify as AROs and are a component of depreciation expense allowed in customer prices. Asset retirement obligation costs are recorded as a regulatory liability as they are collected in prices, and are reduced by actual removal costs incurred.

Regulatory 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 estimates of income taxes 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 prices 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.

During the fourth quarter of 2010, the OPUC staff (Staff) reviewed the 2009 SB 408 reports of PGE and other northwest utilities, with the following two outcomes:

- PGE reached a stipulation with Staff and the Citizens' Utility Board (CUB) on the Company's 2009 SB 408 report, which reduced its original estimated refund to customers of $13 million recorded in 2009 to $8 million. The difference of $5 million was included in Revenues, net in the statement of income for the year ended December 31, 2010. The Industrial Customers of Northwest Utilities (ICNU) has filed objections to the stipulation, claiming customer refunds totaling $61 million are required. In February 2011, PGE filed rebuttal testimony to ICNU's objections, stating ICNU's claim is without merit, asking that the objections be denied, and requesting that the stipulation be approved. A ruling from the OPUC on PGE's 2009 SB 408 report is expected by April 2011.

- Based on the review of the other northwest utilities' 2009 SB 408 reports, Staff determined that the current application of the normalization floor by some of the other utilities in certain calculations was not in accordance with the intent of SB 408. The "normalization floor" was created in the SB 408 rules in 2007 to preserve the federal tax statutory requirement to normalize the benefit of accelerated tax depreciation. In February 2011, the OPUC issued temporary rules that will significantly limit the scope and impact of the normalization floor. Such rules are not expected to have an impact on PGE's 2009 SB 408 report, as the Company was not subject to the normalization floor in 2009.

The temporary rules, which are effective for 180 days, would have an impact on the Company's SB 408 calculation for 2010 if they are adopted permanently. Through September 30, 2010, PGE had recorded a $24 million estimated future collection from customers related to SB 408 for 2010, based on existing rules, which included the application of the normalization floor rule. During the fourth quarter of 2010, PGE reversed this $24 million collection from customers based on the uncertainty of the outcome of the regulatory process and applicable rules. Accordingly, PGE has not recorded any collection from or refund to customers related to SB 408 for 2010 as of December 31, 2010. PGE estimates the collection from customers related to SB 408 for 2010 ranges from less than $1 million, based on the temporary rules, to $33 million, based on existing rules. The 2010 SB 408 report will be filed with the OPUC no later than October 15, 2011, with the OPUC's decision on such report expected no later than April 2012.

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,	
	2010	2009
Trojan decommissioning activities	$ 38	$ 39
Utility plant	16	14
Non-utility property	10	10
Asset retirement obligations	$ 64	$ 63

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 all of the spent fuel is shipped to a U.S. Department of Energy (USDOE) facility, which is not expected prior to 2033.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp) filed a complaint against the USDOE for failure to accept spent nuclear fuel by January 31, 1998. PGE had contracted with the USDOE for the permanent disposal of spent nuclear fuel in order to allow the final decommissioning of Trojan. The plaintiffs paid for permanent disposal services during the period of plant operation and have met all other conditions precedent. The plaintiffs are seeking approximately $128 million in damages. PGE's share of any recovery would be approximately 67%. A trial before the U.S. Court of Federal Claims is scheduled to commence in the fourth quarter of 2011. The Trojan asset retirement obligation will not be impacted by the outcome of this case as such potential recovery is for past decommissioning costs and an asset retirement obligation reflects only future decommissioning expenditures. Any proceeds received related to this legal matter would be returned to customers to offset amounts previously collected related to Trojan decommissioning activities.

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, with the exception of the possible demolition of the powerhouse if an alternative use for the facility is not chosen. Environmental monitoring is scheduled to continue through 2012.

Non-utility property represents ARO's which have been recognized for portions of unregulated properties leased to third parties.

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

	Years Ended December 31,	
	2010	**2009**
Balance as of beginning of year	$ 63	$ 58
Liabilities incurred	1	—
Liabilities settled	(3)	(4)
Accretion expense	4	4
Revisions in estimated cash flows	(1)	5
Balance as of end of year	$ 64	$ 63

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 prices to cover the cost of Trojan decommissioning activities. See "Trust Accounts" in Note 3, Balance Sheet Components, for additional information on the Nuclear decommissioning trust.

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 2013.

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, 2010, PGE was in compliance with this covenant with a 53.4% 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, 2010, PGE had no borrowings and $19 million in commercial paper outstanding under the credit facilities, with $209 million in letters of credit issued. As of December 31, 2010, the aggregate unused available credit under the credit facilities is $372 million.

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

	Years Ended December 31,	
	2010	**2009**
Average daily amount of short-term debt outstanding	$ 9	$ 28
Weighted daily average interest rate *	0.4%	1.3%
Maximum amount outstanding during the year	$ 51	$ 205

* 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, 2010	2009
First Mortgage Bonds, rates range from 3.46% to 9.31%, with a weighted average rate of 5.85% in 2010 and 6.0% in 2009, due at various dates through 2040	$ 1,678	$ 1,550
Pollution Control Revenue Bonds:		
Port of Morrow, Oregon, rates of 5% and 5.2% at December 31, 2010 and 2009, respectively, due 2033	23	23
City of Forsyth, Montana, rates of 5% and 5.2% at December 31, 2010 and 2009, respectively, due 2033	119	119
Port of St. Helens, Oregon, 4.8% to 5.25% rate, due in 2014	10	47
Total Pollution Control Revenue Bonds	152	189
7.875% unsecured notes, due March 10, 2010	—	149
Pollution Control Revenue Bonds owned by PGE	(21)	(142)
Unamortized debt discount	(1)	(2)
Total long-term debt	1,808	1,744

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 2010, PGE issued a total of $128 million of first mortgage bonds as follows:

- On January 15th, $70 million of 3.46% Series due January 2015, with interest payable semi-annually on January 15th and July 15th; and

- On June 15th, $58 million of 3.81% Series due June 2017, with interest payable semi-annually on June 15th and December 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. On March 11, 2010, PGE remarketed $121 million of the Bonds due May 2033 at 5.0%, with interest payable semi-annually on March 1st and September 1st, which are backed by first mortgage bonds. PGE has the option to remarket, through 2033, the $21 million of Bonds held by the Company 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.

In 2008, PGE repurchased $5.8 million of Pollution Control Revenue Bonds Series 1996 (Bonds) issued through the Port of Morrow, which was paid to Lehman as remarketing agent for the Bonds, who in turn paid off the beneficial owner of the Bonds. As a result of the payment, PGE became the beneficial owner of the Bonds and requested that Lehman safe-keep the Bonds in Lehman's Depository Trust Company participant account until such time as the Bonds could be remarketed. After repurchase of the Bonds, PGE removed the liability for the Bonds from its financial statements.

In September 2008, Lehman filed for protection under Chapter 11 of the U.S. Bankruptcy Code in the United States Bankruptcy Court for the Southern District of New York. PGE subsequently filed a claim for return of the Bonds from Lehman. On November 9, 2009, the trustee appointed to liquidate the assets of Lehman (Trustee) allowed PGE's claim as a net equity claim for securities. At the time, PGE believed it would receive back the entire amount of the Bonds at some point during the bankruptcy proceedings.

It is not certain that the Company will receive the full amount of the Bonds but could, along with other claimants, potentially receive a pro-rata share of certain assets. The timing and extent of distributions on claims are subject to the ultimate disposition of numerous claims in the proceedings and certain major contingencies which the Trustee must resolve. PGE cannot currently estimate how much of the value of the Bonds will ultimately be returned to the Company or the timing of the distribution from Lehman. Management does not expect this to have a material effect on the Company's financial position but it could have a material effect on results of operations for a future period.

During 2010, PGE repaid $37 million of 4.8% Port of St. Helens Pollution Control Revenue Bonds. On January 13, 2011, PGE redeemed and retired the remaining $10 million of Port of St. Helens Pollution Control Revenue Bonds outstanding at December 31, 2010.

Other—In addition to the above long-term debt transactions, PGE repaid $149 million of 7.875% unsecured notes on March 15, 2010.

As of December 31, 2010, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:

2011	$	10
2012		100
2013		100
2014		63
2015		70
Thereafter		1,465
	$	1,808

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 of 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 a $30 million contribution to the pension plan in 2010, and no contribution in 2009. The Company does not expect to make any contribution in 2011.

Effective January 31, 2009, the pension plan was closed to new non-bargaining employees, with no changes in benefits to current participants. 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 the description of the Company’s 401(k) plan included in this Note. The pension plan was closed to new bargaining employees as of January 1, 1999.

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 prices 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 2010 and 2009. Contributions approximating $1 million were made to the bargaining unit HRA in 2010 and 2009. No contributions are currently expected to be made to the other postretirement plans in 2011. The measurement date for the postretirement plans is December 31.

Non-Qualified Benefit Plans—The Non-Qualified Benefit Plans (NQBP) in the following tables include obligations for a SERP, which was closed to new participants in 1997, pension benefits for employees that participate in the unfunded MDCP and pension benefits for directors. 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 NQBP—In addition to the non-qualified benefit plans discussed above, PGE provides certain employees and outside directors with deferred compensation plans, whereby participants may defer a portion of their earned compensation. These unfunded plans include the MDCP and the Outside Directors' Deferred Compensation Plan. The Company also provides certain employees with death benefits through a split dollar life insurance policy which pays a fixed amount to the beneficiary and for which the Company has a security interest for the amount of premiums paid. 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 associated with the NQBP included in PGE's balance sheets as of December 31, 2010 and 2009 (in millions):

	2010			2009		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust	$ 19	$ 25	$ 44	$ 20	$ 27	$ 47
Non-qualified benefit plan liabilities *	24	73	97	25	71	96

* For the NQBP, excludes the current portion of $2 million in 2010 and 2009, 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:

	As of December 31, 2010	As of December 31, 2009	Target *
Defined Benefit Pension Plan:			
Equity securities	68%	67%	67%
Debt securities	32	33	33
	100%	100%	100%
Other Postretirement Benefit Plans:			
Equity securities	46%	50%	47%
Debt securities	54	50	53
	100%	100%	100%
Non-Qualified Benefits Plans:			
Debt securities	5%	8%	7%
Equity securities	42	46	42
Insurance contracts	53	46	51
	100%	100%	100%

* The Target for the Defined Benefit Plan represents the mid-point of the investment target range approved by the Investment Committee. Due to the nature of the investment vehicles in both the Other Postretirement Benefit Plans and the Non-Qualified Benefit Plans, these Targets are the weighted average of the mid-point of the respective investment target ranges approved by the Investment Committee. Due to the method used to calculate the weighted average Targets for the Other Postretirement Benefit Plans and Non-Qualified Benefit Plans, reported percentages are affected by the fair market values of the investments within the pools.

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 by asset category are as follows (in millions):

	As of December 31, 2010			
	Level 1	Level 2	Level 3	Total
Defined Benefit Pension Plan assets:				
Equity securities:				
U.S. small cap core	$ 12	$ —	$ —	$ 12
U.S. small cap value	12	—	—	12
U.S. micro cap	14	—	—	14
U.S. large cap growth	—	27	—	27
U.S. large cap value	—	28	—	28
Large cap long/short	—	56	—	56
International large cap growth	—	56	—	56
Fixed income securities:				
U.S. core plus	—	70	—	70
U.S. long government/credit	—	12	—	12
Short duration	—	—	—	—
Mutual funds (1)	135	—	—	135
Private equity funds (2)	—	—	23	23
U.S. large cap futures and U.S. hedge funds (3)	—	—	28	28
	$ 173	$ 249	$ 51	$ 473
Other Postretirement Benefit Plans assets:				
Equity securities:				
U.S. small cap core	$ 1	$ —	$ —	$ 1
U.S. large cap growth	—	1	—	1
U.S. large cap value	—	1	—	1
International large cap growth	—	1	—	1
Fixed income securities:				
Short term investment fund	—	7	—	7
Mutual funds	5	—	—	5
	$ 6	$ 10	$ —	$ 16

(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.

	As of December 31, 2009			
	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.

For information concerning the valuation techniques used to measure fair value presented in the preceding tables, see Note 4, Fair Value of Financial Instruments, and the Levels 1, 2, and 3 discussion.

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 years ended December 31, 2010 and 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
Purchases and sales	4	2	6
Realized gain on sales	1	-	1
Unrealized gain on assets	1	3	4
Balance as of December 31, 2010	$ 23	$ 28	$ 51

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, 2010 and 2009. Obligations related to the Other NQBP, which includes deferred compensation programs and split dollar life insurance for certain employees, are not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2010	2009	2010	2009	2010	2009
Benefit obligation:						
As of January 1	$ 491	$ 467	$ 77	$ 73	$ 27	$ 25
Service cost	11	11	2	2	-	-
Interest cost	28	31	4	4	1	2
Plan amendments	-	1	-	-	-	-
Participants' contributions	-	-	2	2	-	-
Actuarial loss	42	5	1	2	-	2
Benefit payments	(22)	(24)	(7)	(6)	(3)	(2)
As of December 31	$ 550	$ 491	$ 79	$ 77	$ 25	$ 27
Fair value of plan assets:						
As of January 1	$ 406	$ 347	$ 19	$ 19	$ 20	$ 18
Actual return on plan assets	59	83	1	3	2	4
Company contributions	30	-	1	1	-	-
Participants' contributions	-	-	2	2	-	-
Benefit payments	(22)	(24)	(7)	(6)	(3)	(2)
As of December 31	$ 473	$ 406	$ 16	$ 19	$ 19	$ 20
Unfunded position as of December 31	$ (77)	$ (85)	$ (63)	$ (58)	$ (6)	$ (7)
Accumulated benefit plan obligation as of December 31	$ 503	$ 446	N/A	N/A	$ 25	$ 26

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2010	**2009**	**2010**	**2009**	**2010**	**2009**
Amounts included in comprehensive income:						
Net actuarial (gain) loss	$ 22	$ (35)	$ 1	$ —	$ —	$ 2
Prior service cost	—	1	—	—	—	—
Amortization of net actuarial loss	(3)	—	(1)	(1)	(1)	—
Amortization of prior service cost	(1)	(1)	(1)	(1)	—	—
	$ 18	$ (35)	$ (1)	$ (2)	$ (1)	$ 2
Amounts included in AOCL*:						
Net actuarial loss	$ 186	$ 167	$ 20	$ 20	$ 9	$ 9
Prior service cost	2	3	5	6	—	—
	$ 188	$ 170	$ 25	$ 26	$ 9	$ 9
Assumptions used:						
Average discount rate used to calculate benefit obligation	5.47%	5.90%	4.02% - 5.40%	4.66% - 5.92%	5.47%	5.90%
Weighted average rate of increase in future compensation levels	3.80%	3.79%	4.83%	5.07%	N/A	N/A
Long-term rate of return on plan assets	8.50%	8.50%	6.44%	6.88%	N/A	N/A

* 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	
	2010	**2009**	**2010**	**2009**	**2010**	**2009**
Service cost	$ 11	$ 11	$ 2	$ 2	$ -	$ -
Interest cost on benefit obligation	28	31	4	4	1	2
Expected return on plan assets	(39)	(43)	(1)	(1)	-	-
Amortization of transition obligation	-	-	-	-	-	-
Amortization of prior service cost	1	1	1	1	-	-
Amortization of net actuarial loss	3	-	1	1	1	-
Net periodic benefit cost	$ 4	$ -	$ 7	$ 7	$ 2	$ 2

PGE estimates that $12 million will be amortized from AOCL into net periodic benefit cost in 2011, consisting of a net actuarial loss of $8 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					
	2011	2012	2013	2014	2015	2016 - 2020
Defined benefit pension plan	$ 27	$ 31	$ 32	$ 33	$ 35	$ 196
Other postretirement benefits	5	5	5	6	6	28
Non-qualified benefit plans	2	2	2	3	2	11
Total	$ 34	$ 38	$ 39	$ 42	$ 43	$ 235

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, the assumed health care cost trend rates, which can affect amounts reported for the health care plans, were as follows:

- For 2010, 8% annual rate of increase in the per capita cost of covered health care benefits is assumed for 2011 through 2013, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019; and

- For 2009, 7.5% annual rate of increase in the per capita cost of covered health care benefits is assumed for 2010, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2015.

A one-percentage point increase or decrease in the above health care cost assumption would not have a material impact on total service or interest cost, but would increase or decrease the postretirement benefit obligation by $1 million.

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 received 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. PGE made contributions of approximately $15 million during the year ended December 31, 2010 and contributions of $14 million during the year ended December 31, 2009.

NOTE 11: INCOME TAXES

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

	Years Ended December 31, 2010	Years Ended December 31, 2009
Current:		
Federal	$ (20)	$ (46)
State and local	—	—
	(20)	(46)
Deferred:		
Federal	60	71
State and local	13	13
	73	84
Investment tax credit adjustments	—	(2)
Income tax expense	$ 53	$ 36

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, 2010	Years Ended December 31, 2009
Federal statutory tax rate	35.0%	35.0%
Federal tax credits	(10.2)	(8.0)
State and local taxes, net of federal tax benefit	4.3	3.7
Flow through depreciation	0.1	(1.6)
Investment tax credits	—	(1.4)
Other	0.4	(0.3)
Effective tax rate	29.6%	27.4%

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

	As of December 31, 2010	2009
Deferred income tax assets:		
Regulatory liabilities	$ 99	$ 78
Price risk management	73	98
Employee benefits	110	76
Depreciation and Amortization	54	37
Other	72	16
Total deferred income tax assets	408	305
Deferred income tax liabilities:		
Depreciation and amortization	576	436
Price risk management	75	117
Employee benefits	86	48
Regulatory assets	109	48
Other	11	31
Total deferred income tax liabilities	857	680
Deferred income tax liability, net	$ (449)	$ (375)

As of December 31, 2010, PGE had federal and state loss carryforwards of $13 million and $4 million, respectively, which will expire at various dates from 2015 through 2030. In addition, PGE has federal and state tax credit carryforwards of $31 million and $9 million, respectively, which will expire at various dates from 2011 through 2030. PGE believes that it is more likely than not that the benefit from certain state credit carryforwards will not be realized. In recognition of this risk, we have provided a valuation allowance of $2 million on the deferred tax assets relating to these state credit carryforwards as of December 31, 2010. The net change in the total valuation allowance for the year ended December 31, 2010 was a decrease of approximately $1 million. If the Company's assumptions change and it determines it will be able to realize these credits, the tax benefits relating to any reversal of the valuation allowance on deferred tax assets as of December 31, 2010 will be accounted for as a reduction in income tax expense.

As of December 31, 2010, the amount of the Company's unrecognized tax benefit was $2 million, including interest, resulting from a gross increase in a position taken in a prior period. PGE recognizes interest and penalties related to its unrecognized tax benefits in its statements of income. During the year ended December 31, 2010, the Company recognized $1 million in interest and no penalties. PGE believes that it is reasonable that its unrecognized tax benefit will be recognized by the end of 2011 as a result of filing for a federal tax accounting method change.

PGE files income tax returns in the U.S. federal jurisdiction, the states of Oregon and Montana, and certain local jurisdictions. The Internal Revenue Service (IRS) performed an examination of PGE’s income tax returns for 2007 and 2008 during 2010. This audit closed in the first quarter of 2011, with no material findings. In addition, the IRS has informed PGE that examination of the 2006, 2009, and 2010 income tax returns will commence in the third quarter of 2011. The Company is not currently under examination by state or local tax authorities.

NOTE 12: EMPLOYEE STOCK PURCHASE PLAN

PGE has an employee stock purchase plan (ESPP), under which a total of 625,000 shares of the Company may be issued. The ESPP permits all eligible 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 in common 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, 2010 and 2009, the Company issued 28,558 shares and 29,648 shares, respectively, under the ESPP, with proceeds totaling approximately $0.5 million and $0.6 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 3,975,124 shares remain available for future issuance as of December 31, 2010.

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. Performance goals include a return on equity measure and a regulated asset base growth measure. Vesting of Performance Stock Units is 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 is 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, 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
Granted	191,469	19.18
Forfeited	(45,081)	23.45
Vested	(103,223)	25.78
Outstanding as of December 31, 2010	465,428	17.88

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 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 25,942 shares in 2010 and 48,671 shares in 2009. The total value of Restricted and Performance Stock Units vested during the years ended December 31, 2010 and 2009 was $2.7 million and $4.2 million, respectively. 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, 2010 and 2009, PGE recorded $2 million and $1.4 million, respectively, of stock-based compensation expense, which is included in Administrative and general expenses in the statements of income. The recorded stock-based compensation expense of $2 million for 2010 and $1.4 million for 2009 is different than the amount reported in the statements of 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 charge to equity of $0.5 million in 2010 and $1 million in 2009 not reported in Administrative and general expenses in the statements of income.

As of December 31, 2010, unrecognized stock-based compensation expense was $2.9 million, of which $1.9 million and $1 million is expected to be expensed in 2011 and 2012, respectively. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the vesting of 94.2% and 81.2% of awarded Performance Stock Units for 2010 and 2009, respectively, with an estimated 6% 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, 2010 or 2009.

NOTE 14: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2010, PGE's future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2011	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
Capital and other purchase commitments	$ 136	$ 15	$ 13	$ 6	$ 6	$ 26	$ 202
Purchased power and fuel:							
Electricity purchases	111	70	69	66	65	416	797
Capacity contracts	21	20	20	20	19	19	119
Public Utility Districts	9	7	8	8	8	49	89
Natural gas	69	25	20	17	16	16	163
Coal and transportation	21	4	3	—	—	—	28
Operating leases	10	10	10	10	10	202	252
Total	$ 377	$ 151	$ 143	$ 127	$ 124	$ 728	$ 1,650

Capital and other purchase commitments—Certain commitments have been made for capital and other purchases for 2011 and beyond. Such commitments include those related to hydro licenses, 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 2036, and power capacity contracts through 2016. As of December 31, 2010, PGE has power sale contracts with counterparties of approximately $9 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, 2010, there was no outstanding exchange balance pursuant to this exchange contract. 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, 2010, PGE owed 4,191 MWh of electricity, all of which is expected to be delivered by the end of February 2011.

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. The future minimum payments for the Public Utility Districts in the table above reflect the principal payment only and do not include interest, operation, or maintenance expenses. Selected information regarding these projects is summarized as follows (dollars in millions):

	Revenue Bonds as of December 31, 2010	PGE Share: Output	PGE Share: Capacity (in MW)	Contract Expiration	PGE Cost, including Debt Service: 2010	PGE Cost, including Debt Service: 2009
Rocky Reach	$ 329	12.0%	156	2011	$ 9	$ 8
Priest Rapids and Wanapum	907	9.6	192	2052	10	17
Wells	263	19.4	159	2018	7	8
Portland Hydro	13	100.0	36	2017	4	4

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.

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 in 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 $9 million in 2010 and $7 million in 2009.

The future minimum operating lease payments presented is net of sublease income of $3 million in 2011, $2 million in 2012 and 2013, and $1 million in 2014 and 2015. Sublease income is classified as Miscellaneous income in the statements of income and was $3 million in 2010 and 2009.

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 2011 is approximately $100 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, 2010, 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, 2010, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation *	Construction Work in Progress
Boardman	65.00%	1980	$ 439	$ 280	$ 8
Colstrip	20.00%	1986	497	322	5
Pelton/Round Butte	66.67%	1958/1964	211	43	9
Total			$ 1,147	$ 645	$ 22

* Excludes asset retirement obligations and accumulated asset retirement removal costs.

NOTE 16: CONTINGENCIES

Trojan Investment Recovery

Background. In 1993, PGE closed Trojan and sought full recovery of, and a return on, its Trojan 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 return on, 87% of its remaining investment in Trojan.

Court Proceedings on OPUC Authority to Grant Recovery of Return on Trojan Investment. Numerous challenges, appeals and reviews were subsequently filed in various state courts 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 CUB and the Utility Reform Project (URP). In 1998, the Oregon Court of Appeals upheld the OPUC's order authorizing PGE's recovery of the Trojan investment, but held 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 for reconsideration.

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 Trojan. The URP did not participate in the settlement and filed a complaint with the OPUC challenging the settlement agreements. 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. In October 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.

On September 30, 2008, the OPUC issued an order that required 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 $15.4 million amount, plus accrued interest, resulted in a total refund of $33.1 million, payment of which was completed in the first quarter of 2010. The URP and the plaintiffs in the class actions described below have separately appealed the order to the Oregon Court of Appeals.

Class Actions. In a separate legal proceeding, two class action suits were filed in Marion County Circuit Court against PGE in 2003 on behalf of two classes of electric service customers (the Class Action Plaintiffs). The lawsuits 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.

In August 2006, the Oregon Supreme Court issued a ruling ordering the abatement of the class action proceedings until the OPUC responded 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 added 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 Marion County Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings.

In October 2006, the Marion County Circuit Court abated the class actions in response to the ruling of the Oregon

Supreme Court. In October 2007, the Class Action Plaintiffs filed a motion to lift the abatement. In February 2009, the Circuit Court judge denied the motion.

Management cannot predict the ultimate outcome of the above matters. Management believes, however, 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 in future reporting periods.

Complaint and Application for Deferral—Income Taxes

In October 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 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 were not 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.

In August 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 on grounds that it was superfluous to the Complainants' Application 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.

In December 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.

In August 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.

In October 2009, plaintiffs filed an appeal of the August 2009 order with the Oregon Court of Appeals.

Management cannot predict the ultimate outcome of this matter. Management believes, however, that 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. 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 August 2009, PGE filed a motion for summary judgment, alleging that Turlock lacked standing to bring a contract or tort claim against PGE, that damages based on economic loss are not recoverable under a tort claim, and that, under the OAA, the parties have waived their rights to bring tort claims based on the theory of negligence.

In November 2009, the Court denied PGE's motion for summary judgment and set a trial schedule. Subsequently, the trial date was removed from the docket as the parties have reached a tentative settlement, which is pending finalization.

Management cannot predict the outcome of this matter. Management believes, however, that the ultimate outcome will not have a material adverse impact on the Company's financial condition, results of operations or cash flows.

Lawsuit filed by Sierra Club and Other Environmental Groups

On September 30, 2008, the Sierra Club and other environmental groups filed suit against PGE in the U.S. District Court for the District of Oregon (Court) for alleged violations at PGE's Boardman Coal Plant of the federal Clean Air Act (CAA), Oregon's Regional Haze State Implementation Plan (SIP), the plant's CAA Title V permit, and additional alleged violations of various environmental related regulations.

The plaintiffs seek injunctive relief that includes permanently enjoining PGE from operating Boardman 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 for those 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 could be up to approximately $60 million.

On September 30, 2009, the Court ruled on PGE's motion to dismiss most of the claims. In summary, the court denied PGE's motion with respect to most of the plaintiff's claims, but granted PGE's motion with respect to certain claims. The principal claims that remain are (i) that PGE constructed Boardman without complying with the 1974 and 1977 federal pre-construction permitting requirements, (ii) that PGE modified Boardman in the 1990s without complying with Oregon's pre-construction permitting requirements, and (iii) that certain modifications to Boardman triggered New Source Performance Standards (NSPS). Discovery in the case continues, with a tentative trial date set for August 2011.

Management cannot predict the ultimate outcome of the above matters. Management believes, however, 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 in future reporting periods.

EPA Notice of Violation

On September 28, 2010, PGE received a Notice of Violation (NOV) from the U.S. Environmental Protection Agency (EPA). The NOV states that the EPA has determined that PGE is violating the NSPS under the CAA, and Operating Permit requirements under Title V of the CAA, at the Boardman plant. In the NOV, the EPA asserts that certain projects at the Boardman plant completed in 1998 and in 2004 triggered the NSPS, that PGE did not meet the emissions standards required by the regulations and that, therefore, PGE has operated the boiler at the Boardman plant in violation of the CAA. The NOV states the maximum civil penalties the EPA is authorized to impose under the CAA for violations of the NSPS (which range from $25,000 to $37,500 per day), but does not impose any penalties, or specify the amount of any proposed penalties with respect to the alleged violations. Accordingly, management cannot estimate the range of potential liability for the violations asserted in the NOV. However, based solely on the maximum penalties authorized under the CAA, management believes that the maximum penalty that could be imposed for the alleged violations would be approximately $60 million. The projects alleged to have triggered NSPS in the NOV are also included in the Sierra Club's NSPS claims in the litigation described above. Accordingly, to the extent the Company incurs liability for such claims in connection with one of these proceedings, liability for the same claims could not be imposed pursuant to the other proceeding. In the NOV, the EPA has offered PGE an opportunity to confer with the EPA about the violations cited and to present information on the specific findings of the EPA. PGE expects to meet with the EPA during the first quarter of 2011.

Management cannot predict the ultimate outcome of the above matters. Management believes, however, 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 in future reporting periods.

Pacific Northwest Refund Proceeding

In July 2001, the FERC called for a 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 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).

In August 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 in April 2009 issued a mandate giving immediate effect to its August 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.

The settlement between PGE and certain other parties in the California refund case in Docket No. EL00-95, et seq., approved by the FERC in May 2007, resolved all claims 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 did 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, whether the FERC will order refunds in this proceeding, which contracts would be subject to refunds, or how such refunds, if any, would be calculated. Management cannot estimate a range of potential loss. Management believes, however, 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.

EPA Investigation of Portland Harbor

A 1997 investigation by the EPA of a segment of the Willamette River known as the Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the federal National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act as a federal Superfund site and listed 69 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.

In January 2008, the EPA requested information from various parties, including PGE, concerning properties in or near the 5.7 mile segment of the river being examined in the RI/FS, as well as several miles beyond. Subsequently, the EPA has listed additional PRPs, which now number over one hundred.

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

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 or estimate a range of potential loss. Management believes, however, 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.

EPA Investigation of 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. In September 2003, the EPA included the Harbor Oil site 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. In May 2007, an AOC was signed by the EPA and six other parties, including PGE, to implement an RI/FS at the Harbor Oil site. The draft remedial investigation was completed with the resulting report submitted to the EPA.

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 or estimate a range of potential loss. Management believes, however, 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.

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(5,108,804)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(966,975)
3	Preceding Quarter/Year to Date Changes in Fair Value				433,617
4	Total (lines 2 and 3)				(533,358)
5	Balance of Account 219 at End of Preceding Quarter/Year				(5,642,162)
6	Balance of Account 219 at Beginning of Current Year				(5,642,162)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				192,128
8	Current Quarter/Year to Date Changes in Fair Value				42,383
9	Total (lines 7 and 8)				234,511
10	Balance of Account 219 at End of Current Quarter/Year				(5,407,651)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

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	543,352		(4,565,452)	[redacted]	[redacted]
2	(433,617)		(1,400,592)	[redacted]	[redacted]
3			433,617	[redacted]	[redacted]
4	(433,617)		(966,975)	95,365,873	94,398,898
5	109,735		(5,532,427)	[redacted]	[redacted]
6	109,735		(5,532,427)	[redacted]	[redacted]
7	(42,383)		149,745	[redacted]	[redacted]
8			42,383	[redacted]	[redacted]
9	(42,383)		192,128	125,243,947	125,436,075
10	67,352		(5,340,299)	[redacted]	[redacted]

Schedule Page: 122(a)(b) Line No.: 2 Column: e

Comprised of the net amount of the actuarial valuation of $1,585,202 of non-qualified benefit plans net of taxes $(618,227).

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

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

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

Comprised of the net amount of the actuarial valuation of $(272,602) of non-qualified benefit plans net of taxes $80,474.

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 the changes in the fair value of the Price Risk Management Assets and Liabilities designated as cash flow hedges. Consists of ASC 815 Unrealized Market-to-Market Gain of $(70,055) on natural gas forward and swap contracts and Deferred Taxes of $27,672.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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)	6,260,122,796	6,260,122,796
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	6,260,122,796	6,260,122,796
9	Leased to Others		
10	Held for Future Use	12,989,353	12,989,353
11	Construction Work in Progress	124,966,713	124,966,713
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	6,398,078,862	6,398,078,862
14	Accum Prov for Depr, Amort, & Depl	2,858,431,769	2,858,431,769
15	Net Utility Plant (13 less 14)	3,539,647,093	3,539,647,093
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,725,051,756	2,725,051,756
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	133,380,013	133,380,013
22	Total In Service (18 thru 21)	2,858,431,769	2,858,431,769
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)	2,858,431,769	2,858,431,769

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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
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			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2010/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	71,917,395	68,699,478
4	(303) Miscellaneous Intangible Plant	142,019,088	8,811,977
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	213,936,483	77,511,455
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,126,752	
9	(311) Structures and Improvements	215,644,678	157,183
10	(312) Boiler Plant Equipment	433,206,795	3,115,114
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	133,380,071	4,742,948
13	(315) Accessory Electric Equipment	46,320,754	5,908
14	(316) Misc. Power Plant Equipment	12,365,029	232,155
15	(317) Asset Retirement Costs for Steam Production	4,322,203	748,137
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	849,366,282	9,001,445
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	6,047,626	
28	(331) Structures and Improvements	34,753,410	1,488,357
29	(332) Reservoirs, Dams, and Waterways	150,612,439	77,731,742
30	(333) Water Wheels, Turbines, and Generators	45,550,278	311,869
31	(334) Accessory Electric Equipment	13,696,630	331,225
32	(335) Misc. Power PLant Equipment	1,812,377	18,525
33	(336) Roads, Railroads, and Bridges	8,777,363	495,954
34	(337) Asset Retirement Costs for Hydraulic Production	4,276	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	261,254,399	80,377,672
36	D. Other Production Plant		
37	(340) Land and Land Rights	48,946	
38	(341) Structures and Improvements	99,799,134	15,881,336
39	(342) Fuel Holders, Products, and Accessories	116,691,188	-1,408,887
40	(343) Prime Movers		
41	(344) Generators	885,821,940	353,417,424
42	(345) Accessory Electric Equipment	44,980,067	16,628,910
43	(346) Misc. Power Plant Equipment	7,724,982	105,362
44	(347) Asset Retirement Costs for Other Production	1,578,322	635,626
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,156,644,579	385,259,771
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,267,265,260	474,638,888

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2010/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	11,126,862	
49	(352) Structures and Improvements	15,238,975	438,175
50	(353) Station Equipment	200,822,902	10,175,367
51	(354) Towers and Fixtures	46,913,776	-107,728
52	(355) Poles and Fixtures	17,149,608	342,968
53	(356) Overhead Conductors and Devices	72,313,538	88,399
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)	363,905,032	10,937,181
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	13,123,709	
61	(361) Structures and Improvements	33,191,504	1,254,554
62	(362) Station Equipment	311,995,327	21,021,643
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	283,651,419	13,898,136
65	(365) Overhead Conductors and Devices	457,171,682	24,863,635
66	(366) Underground Conduit	15,761,990	
67	(367) Underground Conductors and Devices	558,955,221	25,621,429
68	(368) Line Transformers	271,992,723	8,054,654
69	(369) Services	352,616,718	7,572,870
70	(370) Meters	105,736,698	38,927,175
71	(371) Installations on Customer Premises	376,133	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	54,530,393	1,280,925
74	(374) Asset Retirement Costs for Distribution Plant	460,131	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,459,563,648	142,495,021
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	57,392,890	3,231,054
88	(391) Office Furniture and Equipment	50,516,478	10,784,055
89	(392) Transportation Equipment	41,323,243	1,947,152
90	(393) Stores Equipment	493,065	56,533
91	(394) Tools, Shop and Garage Equipment	10,580,531	381,856
92	(395) Laboratory Equipment	11,959,819	709,638
93	(396) Power Operated Equipment	41,364,573	4,305,248
94	(397) Communication Equipment	58,379,071	4,396,343
95	(398) Miscellaneous Equipment	166,228	2,878
96	SUBTOTAL (Enter Total of lines 86 thru 95)	277,049,048	25,814,757
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)	277,113,536	25,814,757
100	TOTAL (Accounts 101 and 106)	5,581,783,959	731,397,302
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)	5,581,783,959	731,397,302

Name of Respondent Portland General Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/30/2012	Year/Period of Report End of 2010/Q4

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			140,616,873		3
5,602,986			145,228,079		4
5,602,986			285,844,952		5
					6
					7
			4,126,752		8
		26,399	215,828,260		9
1,174,054		-20,524,593	414,623,262		10
					11
		20,385,319	158,508,338		12
21,838			46,304,824		13
105,374		-364,856	12,126,954		14
			5,070,340		15
1,301,266		-477,731	856,588,730		16
					17
					18
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					26
			6,047,626		27
127,825			36,113,942		28
685,811			227,658,370		29
4,751			45,857,396		30
8,554		18,403	14,037,704		31
10,011			1,820,891		32
			9,273,317		33
			4,276		34
836,952		18,403	340,813,522		35
					36
			48,946		37
		-1,740,646	113,939,824		38
58,912		-67,691	115,155,698		39
					40
517,658		67,691	1,238,789,397		41
399,528		532,635	61,742,084		42
132,181		1,208,011	8,906,174		43
			2,213,948		44
1,108,279			1,540,796,071		45
3,246,497		-459,328	2,738,198,323		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
			11,126,862		48
232		175,013	15,851,931		49
1,056,602		-1,713,423	208,228,244		50
			46,806,048		51
8,205			17,484,371		52
			72,401,937		53
					54
					55
			286,332		56
			53,039		57
1,065,039		-1,538,410	372,238,764		58
					59
		530,528	13,654,237		60
13,920		-721,142	33,710,996		61
2,859,739		2,062,866	332,220,097		62
					63
1,719,234			295,830,321		64
2,369,939			479,665,378		65
22,053			15,739,937		66
288,157			584,288,493		67
1,419,128		-24,743	278,603,506		68
149,356			360,040,232		69
25,011,240		17,771	119,670,404		70
			376,133		71
					72
235,131			55,576,187		73
			460,131		74
34,087,897		1,865,280	2,569,836,052		75
					76
					77
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					82
					83
					84
					85
			4,873,150		86
421,209		-46,719	60,156,016		87
4,364,436		3,101	56,939,198		88
2,988,365		287,871	40,569,901		89
229,269		2,021,097	2,341,426		90
42,032			10,920,355		91
61,589		204	12,608,072		92
1,291,452		-1,947,896	42,430,473		93
156,797		345,329	62,963,946		94
31,426			137,680		95
9,586,575		662,987	293,940,217		96
					97
			64,488		98
9,586,575		662,987	294,004,705		99
53,588,994		530,529	6,260,122,796		100
					101
					102
					103
53,588,994		530,529	6,260,122,796		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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					
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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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	Evergreen, Washington County, OR	2008	Various	2,603,754
5	Horizon, 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	1,774,021
8	Shute Road, Washington County, OR	2009	Various	1,721,229
9	Highway 26 Easements, Washington County, OR	2009	Various	278,500
10	Evergreen Easement, Washington County, OR	2009	Various	334,928
11	Other Land and Land Rights (7 in Number)	Various	Various	187,789
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
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47	Total			12,989,353

Name of Respondent Portland General Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/30/2012	Year/Period of Report End of 2010/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	Financial System - Software Purchase & Implementation	15,844,639
2	Coyote Springs - Combustion Turbine Upgrade	15,431,695
3	California-Oregon Intertie (COI) - Transmission Line Upgrade	12,229,360
4	Advanced Metering Infrastructure	7,993,158
5	SE Portland 4-Kv Conversion	5,446,401
6	Pelton/Round Butte - Fish Passage	4,450,627
7	New Facility - (Avery) Land & Building Purchase	3,994,278
8	Boardman - Air Quality & Combustion Controls	3,872,380
9	Inventory Work Management - Software Purchase & Installation	3,493,364
10	North Fork - Fish Passage Improvement	2,734,024
11	Sullivan - Fish Passage	2,695,879
12	Colstrip - Capital projects	2,671,197
13	River Mill - Fish Passage Improvement	2,295,690
14	River District - Install Vaults	2,227,454
15	IT Cyber Security Improvement	1,953,763
16	Colstrip - Turbine Purchase	1,889,557
17	Upgrade PGE Web Infrastructure	1,878,790
18	Boardman - Replace boiler reheater	1,727,492
19	Abernathy Substation - Replace Metal-Clad Switchgear & Upgrade Substation	1,721,336
20	Coyote Springs - Combustion Casing Replacement	1,709,888
21	Tigard Substation - Add A New Feeder & Upgrade Substation	1,635,412
22	Scholls Ferry Substation - Construct A New Substaion	1,601,147
23	Pelton/Round Butte - Deschutes River Conservancy	1,499,684
24	Pelton/Round Butte - Day Use Area & Campground Improvements	1,228,628
25	McLoughlin Substation - Replace Obsolete Relays	1,129,771
26	Dispatchable Generation - Installation	1,121,664
27	Keeler Substation - Add 230-Kv Circuit Breaker	1,033,809
28	Boardman - Air Quality, Mercury Controls	898,070
29	Rewind Capitalized Spare Transformer	838,983
30	Banks Substation - Convert To Breaker Substation	831,855
31	Customer Service Technology - Mobile Devices	803,512
32	World Trade Center - Replace UPS And Battery Systems	751,331
33	Gresham Substation - Replace Transformer Load Tap Changer & Gas Monitor	646,990
34	Colstrip - Waste Water Treatment Plant	641,361
35	Bethel-Round Butte 230-Kv Line - Transmission Pole Replacement	547,557
36	Environmental Services - Software Purchase & Implementation	534,251
37	Boardman - Install Gear Driven Coal Orifices	504,036
38	Alarm Monitoring For Communication Technology Systems	503,414
39	PGE Technology Updates	494,679
40	Rewind Failed Transformer & Replace Load Tap Changer	456,959
41	Coyote Springs - Install New Exhaust Diffuser	362,583
42	Pelton\Round Butte - Install Shoreline Erosion Control Measures	337,967
43	TOTAL	124,966,713

Name of Respondent Portland General Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/30/2012	Year/Period of Report End of 2010/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	Bethel-McLoughlin 230-Kv Line - Transmission Pole Replacement	332,696
2	St. Mary's East Substation - Install SCADA System	316,021
3	Upgrade PBX Software	298,643
4	Oak Grove - Install Harriet Lake Flow Release Structure	293,671
5	Beaver-Alston 230-Kv Line - Transmission Pole Replacement	288,769
6	Mt. Angle Substation - Replace Impedance Relays	287,463
7	Round Butte - Rewind Generator #1	271,030
8	River Mill - Fish Passage	268,376
9	Oak Grove - Install 11-Kv Bus Tie & Upgrade Station Service	253,453
10	Cornell Substation - New Substation Site Permitting	237,307
11	McLoughlin Substation - Transformer Storage Yard Addition	236,862
12	Scholls Ferry Substation - New Substation Site Permitting	226,605
13	Murrayhill Substation - Install New 115-Kv Breaker Position	221,510
14	Tigard Substation - Install SCADA System	220,096
15	Customer Callback - Software & Hardware Purchase	219,542
16	Oak Grove - Install Storm Water Drainage System	216,893
17	Sherwood Substation - Add Fiber Optic Link To BPA Pearl Substation	208,019
18	Power Scheduling Accounting System -Transmission	206,876
19	Coyote Springs - Install Heat Exchanger To Incoming Fuel Line	192,023
20	Image Services - Software Purchase & Implementation	189,153
21	Timothy Lake - Recreation Lake Improvements	182,381
22	Pelton/Round Butte - Lower River Improvements	176,413
23	Boardman - Optimize Intake Water Temperature	170,356
24	Fiber Optics - Wilsonville To Oregon City Installation	166,224
25	Dunn's Corner Substation - Relocate Relays From Bull Run Switchyard	153,313
26	Stephens Substation - Replace BK Transformer Relays	150,082
27	Twilight Substation - New 57-Kv Connection To Westcott Substation	149,815
28	Canyon Substation - Add Breaker Racking System	148,925
29	Malin Substation - Road Improvements	141,393
30	Pelton/Round Butte - Mitigation Fund	134,343
31	Boardman - Upgrade Coal Mill CO Monitors	117,724
32	Horizon-BPA Keeler 230-Kv Line - Construct New Transmission Line	111,904
33	Pelton/Round Butte - Offshore Morage	109,994
34	Gresham Substation - Replace Impedance Relays	107,582
35	Timothy Lake - Pine Point Campground Improvements	104,471
36	Port Westward - Install 230-Kv Metering Curent Transformers	104,086
37	Work Orders < 100,000	3,088,064
38		
39		
40		
41		
42		
43	TOTAL	124,966,713

Schedule Page: 216 Line No.: 6 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. Respondent'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.: 16 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.: 18 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.: 23 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.: 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 Line No.: 27 Column: a

Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switch and/or regulating equipment.

Schedule Page: 216 Line No.: 28 Column: a

Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing, BSC, LLC. Resondent's 65% share of jointly owned costs is reported.

Schedule Page: 216 Line No.: 34 Column: a

Jointly owned with Northwestern Energy LLC, PP&L Montana, LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Coporation. Respondent's 20% share of jointly owned costs is reported.

Schedule Page: 216 Line No.: 37 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.: 42 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.: 7 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.: 22 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.: 23 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: 216.1 Line No.: 30 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.: 31 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: 216.1 Line No.: 33 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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	2,563,026,345	2,563,026,345		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	208,952,081	208,952,081		
4	(403.1) Depreciation Expense for Asset Retirement Costs	272,063	272,063		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	5,309,560	5,309,560		
7	Other Clearing Accounts	629,987	629,987		
8	Other Accounts (Specify, details in footnote):	10,767	10,767		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	215,174,458	215,174,458		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	47,987,023	47,987,023		
13	Cost of Removal	7,993,404	7,993,404		
14	Salvage (Credit)	2,818,756	2,818,756		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	53,161,671	53,161,671		
16	Other Debit or Cr. Items (Describe, details in footnote):	12,624	12,624		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,725,051,756	2,725,051,756		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	594,949,304	594,949,304		
21	Nuclear Production				
22	Hydraulic Production-Conventional	127,118,026	127,118,026		
23	Hydraulic Production-Pumped Storage				
24	Other Production	327,579,677	327,579,677		
25	Transmission	163,145,969	163,145,969		
26	Distribution	1,380,886,914	1,380,886,914		
27	Regional Transmission and Market Operation				
28	General	131,371,866	131,371,866		
29	TOTAL (Enter Total of lines 20 thru 28)	2,725,051,756	2,725,051,756		

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

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

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

Adjustment as part of transfer of transformer from Beaver 8 to co-owned Pelton hydro station.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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			45,876
4	Sub - TOTAL			46,876
5				
6	Salmon Springs Hospitality Group			
7	Common Stock	04/09/98		10,000
8	Equity in Earnings			-711,221
9	Sub - TOTAL			-701,221
10				
11	SunWay 1, LLC			
12	Paid in Capital	5/29/08		156,273
13	Equity in Earnings			-109,974
14	Sub - TOTAL			46,299
15				
16	SunWay 2, LLC			
17	Paid in Capital	9/16/08		525,014
18	Equity in Earnings			-215,942
19	Sub - TOTAL			309,072
20				
21	SunWay 3, LLC			
22	Paid in Capital	10/19/09		
23	Equity in Earnings			
24	Sub - TOTAL			
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 2,490,770		TOTAL	-298,974

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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
28,113		73,989		3
28,113		74,989		4
				5
				6
		10,000		7
346,612		-364,609		8
346,612		-354,609		9
				10
				11
		156,273		12
-1		-109,975		13
-1		46,298		14
				15
				16
		525,014		17
20		-215,922		18
20		309,092		19
				20
				21
	2,415,395	2,415,395		22
-395		-395		23
-395	2,415,395	2,415,000		24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
374,349	2,415,395	2,490,770		42

Schedule Page: 224 Line No.: 14 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.

<u>SunWay 1, LLC statistics at 12/31/2010 (100%)</u>

In-service Production cost: $1,097,814
Total installed capacity: 104 kW
Operations and Maintenance for 2010: $50,058

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).

<u>SunWay 2, LLC statistics at 12/31/2010 (100%)</u>

In-service Production cost: $5,922,280
Total installed capacity: 1.1 MW
Operations and Maintenance for 2010: $104,200

Schedule Page: 224 Line No.: 22 Column: f

Consists of PGE's capital contribution to SunWay 3, LLC in 2010.

Schedule Page: 224 Line No.: 24 Column: g

Represents PGE's share of SunWay 3, LLC, a variable interest entity jointly owned by PGE (0.01% interest) and Firstar Development, LLC, a wholly-owned subsidiary of US Bank, (99.99% interest). SunWay 3, LLC was formed for the sole purpose of (1) designing, developing, constructing, owning, maintaining, operating, and financing seven photovoltaic solar power facilities located on the rooftops of seven 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).

<u>SunWay 3, LLC statistics at 12/31/2010 (100%)</u>

In-service Production cost: $7,569,786
Total installed capacity: 2.4 MW
Operations and Maintenance for 2010: $387,078

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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)	23,897,315	21,503,107	Generation
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)	12,986,346	14,088,552	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	17,046,858	14,866,105	Generation
8	Transmission Plant (Estimated)	6,905	103,952	Transmission
9	Distribution Plant (Estimated)	1,272,332	1,380,713	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	120,642	347,155	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	31,433,083	30,786,477	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	11,357	6,081	Customer Service
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	3,051,673	2,944,884	Various
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	58,393,428	55,240,549	

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

Balance primarily relates to costs associated with purchased renewable energy certificates.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2011 No. (d)	2011 Amt. (e)
1	Balance-Beginning of Year	29,037.00	360,000	10,029.00	
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	11,204.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	17,833.00	360,000	10,029.00	
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	1,152.42		144.12	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	144.78			
40	Balance-End of Year	1,007.64		144.12	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2012		2013		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
10,032.00		10,029.00		180,556.00		239,683.00	360,000	1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						11,204.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
10,032.00		10,029.00		180,556.00		228,479.00	360,000	29
								30
								31
								32
								33
								34
								35
144.12		144.12		4,765.86		6,350.64		36
								37
								38
				144.78		289.56		39
144.12		144.12		4,621.08		6,061.08		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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2011 No. (d)	2011 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2012		2013		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
								7
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								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) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2010/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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;	297,202,920	-10,712,020	407	4,646,000	3,368,428
24	PGE has the authority to continue			182.3	-18,726,448	
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	297,202,920	-10,712,020		-14,080,448	3,368,428

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	CCCT NITS - System Impact Study	132	561.6	132	456
3	Trojan-Horizon Project	38,659	561.6	38,659	456
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Southern Crossing - Boardman	634	561.7	634	456
23	419MW - CCCT at Boardman	18,254	561.7	18,254	456
24	200MW Beaver Plant Site	15,335	561.7	15,335	456
25	Martinsdale Wind Project	805	561.7	805	456
26	Boardman Facilities Study	20,866	561.7	20,866	456
27	Coyote Facility Study	13,259	561.7	13,259	456
28	Interconnection Study - Maupin	19,597	561.7	19,597	456
29	Martinsdale Wind - SIS	498	561.7	498	456
30	Rock Creek Lg Gen Interconnect Sty	5,298	561.7	5,298	456
31	Coyote Springs SIS Re-Study	20,889	561.7	20,889	456
32	Boardman SIS Re-Study	21,074	561.7	21,074	456
33	Coyote Springs NITS SIS	127	561.7	127	456
34	Boardman NITS System Impact Study	40	561.7	40	456
35	CCCT NITS - System Impact Study	45	561.7	45	456
36	Warm Springs Facilities Study	747	561.7	747	456
37	Martinsdale - Facilities	309	561.7	309	456
38	Rock Creek Wind Energy Project	2,336	561.7	2,336	456
39	BP Wind Energy Inc - Application	10,997	561.7	10,997	456
40	Trojan-Horizon Project	24,926	561.7	24,926	456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	First Wind LGIA	1,152	561.7	1,152	456
23	Pacific Wind Application Deposit	604	561.7	604	456
24	419MW - CCCT at Boardman	11,072	561.7	11,072	456
25	Other	29,059	561.7	29,059	456
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231.1 Line No.: 25 Column: b

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2010/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Colstrip Common Facilities (28 year amort.	2,362,367		407.3	322,140	2,040,227
2	ending 2017, FERC OCA-AD					
3	letter dtd 5/23/1989)					
4						
5	Pelton Round Butte Transition Costs	488,586	14,083	182.3	502,669	
6	(per OPUC Order No. 00-459 dtd 8/22/2000)					
7						
8	Category A Advertising Deferral (Year 2)	183,718	5,295	229	189,013	
9	(per OPUC Order No. 03-601 dtd 10/09/2003)					
10						
11	Category A Advertising Deferral (Year 3)	170,643	4,919	229	175,562	
12	(per OPUC Order No. 04-562 dtd 9/28/2004)					
13						
14	Intervenor Funding (original deferral per OPUC	682,799	356,401	407.3 /	14,960	1,024,240
15	Order No. 03-388 dtd 7/02/2003; current year			182.3		
16	reauthorization approved through various					
17	OPUC Orders)					
18						
19	FERC Settlement	18,650	538	229	19,188	
20	(Docket No. EL01-114 et al., dtd 11/10/2003)					
21						
22	Beaver Unit 8 Deferral	184,700	5,866	182.3	190,566	
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	67,246,491	13,981,535	282	12,002,496	69,225,530
27	Previously Flowed to Customers	40,886,649	9,124,371	283	7,836,338	42,174,682
28	(Amort. period is based on the lives of the	106,563	4,071			110,634
29	properties, approximately 25 years.)					
30						
31	Grid West Loans	1,705,224	100,631	182.3/229	1,805,855	
32	(per OPUC Order No. 06-483 dtd 8/22/2006)					
33						
34	Senate Bill 408 Deferral - YR 2006		433,364	449.1	295,414	137,950
35	(per OPUC Order No. 10-129 dtd 4/06/2010,					
36	amortization period: 6/1/2010 - 5/31/2011)					
37						
38	Senate Bill 408 Deferral - YR 2007	7,288,618	42,620	449.1	7,081,012	250,226
39	(per OPUC Order No. 10-129 dtd 4/06/2010,					
40	amortization period: 6/1/2010 - 5/31/2011)					
41						
42						
43						
44	TOTAL	654,999,079	339,444,558		238,655,148	755,788,489

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Pension Funding	169,772,900	22,073,110	219	4,244,560	187,601,450
2	Postretirement Funding	25,993,729	1,060,026	219	1,918,549	25,135,206
3	(per SFAS No. 158 adopted 12/31/2006;					
4	OPUC Order No. 07-051 dtd 02/12/2007)					
5						
6	Boardman Power Cost Deferral	18,547,757	178,691	182.2/254	18,726,448	
7	(deferred per OPUC Order No. 07-049					
8	dtd 2/12/2007; recovery per OPUC Order					
9	No. 10-051 dtd 2/11/2010)					
10						
11	CIST/IT Deferral	81,385	2,346	229	83,731	
12	(per OPUC Order No. 01-777 dtd 8/31/2001)					
13						
14	Price Risk Management	242,934,624	235,273,359	Various	117,704,289	360,503,694
15						
16	Deferred Broker Settlement	49,503,536	27,201,881	555	53,138,401	23,567,016
17						
18	Tojan Refund Deferral - Incremental Costs	2,310,429	501,662			2,812,091
19	(per OPUC Order No. 09-133 dtd 4/14/2009)					
20						
21	Senate Bill 408 Deferral Local - Residual 2007		372,332			372,332
22	Multnomah County Business Income Tax					
23						
24	Direct Access Open Enrollment Deferral - 2008	469,504		447	2,080	467,424
25	(per Advice No. 10-22A dtd 12/28/2010					
26	amortization period: 1/1/2011 - 12/31/2011)					
27						
28	Direct Access Open Enrollment Deferral - 2009	892,391	46,717	447	830,763	108,345
29	(per Advice No. 09-22 dtd 12/22/2009					
30	amortization period: 1/1/2010 - 12/31/2010)					
31						
32	Independent Evaluator Deferral	263,518	22,678			286,196
33	(per OPUC Order No. 08-010 dtd 1/14/2008)					
34						
35	Smart Meter Project Office Costs	1,181,364	101,666			1,283,030
36	(per OPUC Order No. 08-209 dtd 4/11/2008)					
37						
38	Schedule 110 EE - Asset Bal. Acct	43,844	293,689	254/407.3	337,533	
39	(per Advice No. 07-25 dtd 5/20/2008)					
40						
41	Smart Meter Severance Deferral	1,835,000		930.2	1,835,000	
42	(amortization period: 1/1/2009 - 12/31/2010)					
43						
44	TOTAL	654,999,079	339,444,558		238,655,148	755,788,489

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	WECO Deferral	1,349,953	39,918	501/182.3	1,389,871	
2	(per Advice No. 08-16 dtd 7/24/2009					
3	amortization period: 8/1/2009 - 7/31/2010)					
4						
5	Biglow Canyon Phase 2 Deferral	10,629,811	161,726	456	6,253,582	4,537,955
6	(per OPUC Order No. 09-398 dtd 10/05/2009 &					
7	OPUC Order No. 10-391 dtd 10/11/2010;					
8	amortization period: 01/01/2010 - 12/31/2011)					
9						
10	SunWay Deferral	92,838	172,305	456	86,103	179,040
11	(per OPUC Order No. 09-398 dtd 10/05/2009					
12	amortization period: 1/1/2010 - 12/31/2010)					
13						
14	Residential Critical Peak Pricing Pilot	8,703		908	8,703	
15	(pilot program not operational)					
16						
17	Generation Plant Maintenance Deferral	6,160,428		553	684,492	5,475,936
18	(per OPUC Order No. 08-601 dtd 12/29/2008					
19	amortization period: 1/1/2009 - 12/31/2018)					
20						
21	Small Nonres Sch 123 SNA Deferral-2009	1,497,783	526,720	456	975,830	1,048,673
22	Small Nonres Sch 123 SNA Deferral-2010		2,350,099			2,350,099
23	Residential Sch 123 SNA Deferral-2010		4,161,613			4,161,613
24	(per OPUC Order No. 09-162 dtd 5/6/2009;					
25	reauthorization OPUC Order No. 10-077 dtd					
26	3/2/2010)					
27						
28	Stable Rate Revenue Balancing Acct	104,574	156,238			260,812
29	(per Advice No. 06-13 dtd 6/22/2006)					
30						
31	Photovoltaic Volumetric Incentive Pilot		232,779			232,779
32	(per OPUC Order No. 10-198 dtd 5/28/10)					
33						
34	Biglow Canyon Phase 3 Deferral		17,763,375			17,763,375
35	(per OPUC Order No. 10-391 dtd 10/11/2010;					
36	amortization period: 1/1/2011 - 12/31/2011)					
37						
38	Residual Deferred Account		637,934			637,934
39	(per OPUC Order No. 10-279 dtd 7/23/2010)					
40						
41	City of Glendale Wholesale Sales		2,040,000			2,040,000
42	(FERC Docket No. ER10-1286-000)					
43						
44	TOTAL	654,999,079	339,444,558		238,655,148	755,788,489

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

The residual balance remaining after the authorized amortization period was combined into the Residual Deferred Account pursuant to OPUC Order No. 10-279, dated July 23, 2010.

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

The residual balance was offset against an OPUC regulatory fee refund pursuant to OPUC Order No. 10-372, dated September 22, 2010.

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

The residual balance was offset against an OPUC regulatory fee refund pursuant to OPUC Order No. 10-372, dated September 22, 2010.

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

Current year reauthorization approved through OPUC orders:
10-006, dated 01/06/2010, Intervenor Fund Grant
10-332, dated 08/18/2010, Intervenor Matching Fund Grant
10-005, dated 01/06/2010, Intervenor Issue Fund Grant
10-007, dated 01/06/2010, Intervenor Issue Fund Grant
10-008, dated 01/06/2010, Intervenor Issue Fund Grant
10-120, dated 04/02/2010, Intervenor Issue Fund Grant
10-122, dated 04/02/2010, Intervenor Issue Fund Grant
10-274, dated 07/22/2010, Intervenor Issue Fund Grant
10-275, dated 07/22/2010, Intervenor Issue Fund Grant
10-285, dated 07/26/2010, Intervenor Issue Fund Grant
10-320, dated 08/12/2010, Intervenor Issue Fund Grant
10-359, dated 09/16/2010, Intervenor Issue Fund Grant
10-470, dated 12/08/2010, Intervenor Issue Fund Grant

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

The residual balance remaining after the authorized amortization period was combined into the Residual Deferred Account pursuant to OPUC Order No. 10-279, dated July 23, 2010.

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

The residual balance was offset against an OPUC regulatory fee refund pursuant to OPUC Order No. 10-372, dated September 22, 2010.

Schedule Page: 232 Line No.: 22 Column: d

The residual balance remaining after the authorized amortization period was combined into the Residual Deferred Account pursuant to OPUC Order No. 10-279, dated July 23, 2010.

Schedule Page: 232 Line No.: 31 Column: d

A portion of the residual balance was offset against an OPUC regulatory fee refund pursuant to OPUC Order No. 10-372, dated September 22, 2010. The remaining residual balance was combined into the Residual Deferred Account pursuant to OPUC Order 10-279, dated July 23, 2010.

Schedule Page: 232.1 Line No.: 6 Column: e

Pursuant to OPUC Order No. 10-051, dated February 11, 2010, the remaining deferred balance plus accrued interest was recovered in 2010 with offsetting credits 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

The residual balance was offset against an OPUC regulatory fee refund pursuant to OPUC Order No. 10-372, dated September 22, 2010.

Schedule Page: 232.1 Line No.: 14 Column: d

Amounts charged to Accounts 555, 547, and 219.

Schedule Page: 232.1 Line No.: 18 Column: f

Balance represents incremental costs, including accrued interest, incurred to administer the Trojan Refund which was mandated per OPUC Order No. 08-487, dated September 30, 2008.

Schedule Page: 232.1 Line No.: 38 Column: e

Reclassified credit balance of ($343,128) from Regulatory Asset to Regulatory Liability.

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

The residual balance remaining after the authorized amortization period was combined into the Residual Deferred Account pursuant to OPUC Order No. 10-279, dated July 23, 2010.

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

The residual balance remaining after the initial amortization period ended 12/31/2010 was approved for recovery in OPUC Order No. 10-391, dated October 11, 2010, over 12 months beginning 01/01/2011 (per PGE's approved Tariff Schedule 122).

Schedule Page: 232.2 Line No.: 21 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. The amortization period is 12 months beginning June 1, 2010.

Schedule Page: 232.2 Line No.: 22 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.: 23 Column: f

Balance represents amounts deferred for residential 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.: 28 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.

Schedule Page: 232.2 Line No.: 31 Column: f

Balance represents the deferral of costs for a pilot program to demonstrate the use and effectiveness of volumetric incentive rates and payments for electricity delivered by solar photovoltaic energy systems.

Schedule Page: 232.2 Line No.: 34 Column: f

Balance represents the deferred incremental revenue requirement to recover costs associated with Phase 3 of the Biglow Canyon Wind Farm which went into service in 2010. Recovery was approved in OPUC Order No. 10-391, dated October 11, 2010, and will be amortized over 12 months beginning 01/01/2011 under the Renewable Resources Adjustment Clause pursuant to PGE’s tariff Schedule 122.

Schedule Page: 232.2 Line No.: 38 Column: f

Balance represents the combined residual balances of deferred accounts past their authorized amortization period pursuant to OPUC Order No. 10-279, dated July 23, 2010.

Schedule Page: 232.2 Line No.: 41 Column: f

Balance represents the deferral of the portion of the Glendale Settlement representing reduced revenues for 2011 and 2012. Recovery of the 2011 reduced revenues (increased Net Variable Power Costs) was included in the 2011 General Rate Case/Annual Power Cost Update Tariff (GRC/AUT) filings and will be amortized over 12 months beginning 01/01/2011. The reduced revenue for 2012 will be included in the 2012 AUT filings.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	(2 items as of 12/31/2010)	28,582	62,117	Various	53,591	37,108
3						
4	Net Trust Contributions	4	83,346,898	Various	81,691,897	1,655,005
5						
6	Pebble Springs AFDC - amort.					
7	over service lives of related					
8	property	291,535	2,580	425	36,300	257,815
9						
10	Tax Credit Sale - amort. over					
11	service lives of related					
12	property	4,754		421	2,580	2,174
13						
14	NWNG Capital Contribution -					
15	amort. ended 10/31/2010	166,650		547	166,650	
16						
17	Deferred Wheeling Costs -					
18	amort. over 25 yrs through 2012	538,905		565	196,416	342,489
19						
20	Deferred Rent - WTC Tenant					
21	amort. over 10 yrs through 2013	97,731	75,000	418	44,650	128,081
22						
23	Deferred Revolving Credit					
24	Agreement Fees	1,814,323	21,051	431	700,812	1,134,562
25						
26	Dispatchable Generation					
27	various amort. periods beg in					
28	2000 and extending thru 2017	4,658,835	2,320,729	903	645,920	6,333,644
29						
30	Potential Sale of Supply					
31	Portfolio	1,534	245,841	254	247,375	
32						
33	LID Receivable from WTC Tenants					
34	amort over 20 yrs through 2030	119,785			5,990	113,795
35						
36	Colstrip Operations	33,725	873,918	Various	907,643	
37						
38	Colstrip - Lime Contract					
39	amort. over 4 yrs. 2011 - 2014	2,170,322	682,000	Various	302,322	2,550,000
40						
41	Coyote2 LLC		2,109,987	Various	1,997,664	112,323
42						
43						
44						
45						
46						
47	Misc. Work in Progress	268,912				162,648
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	10,195,597				12,829,644

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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 & Amortization	35,010,276	36,407,372
3	Regulatory Liabilities	35,537,010	98,602,479
4	Employee Benefits	93,631,476	109,531,442
5	Price Risk Management	98,199,241	72,737,813
6	Asset Retirement Obligation	11,110,208	12,358,176
7	Other	21,534,956	69,074,205
8	TOTAL Electric (Enter Total of lines 2 thru 7)	295,023,167	398,711,487
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	9,527,576	9,231,989
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	304,550,743	407,943,476

Notes

	Balance at Beginning of Year	Balance at End of Year
Line 7 - Other		
Bad Debt Expense	$ 2,189,340	$ 2,078,737
Nuclear Decommissioning Trust	8,989,981	1,532,307
Deferred Tax Credits	5,011,324	39,723,079
Net Operating Losses	0	16,066,568
Miscellaneous Other	5,344,311	9,673,514
Total Line 7 - Other	$21,534,956	$69,074,205
Line 17 - Other - NonUtility		
Depreciation & Amortization	$5,780,094	$ 5,622,778
Software Costs	820,308	334,170
Miscellaneous	2,927,174	3,275,041
Total Line 17 - Other - NonUtility	$9,527,576	$ 9,231,989

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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				
11				
12				
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42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
75,316,419	823,989,481					2
						3
75,316,419	823,989,481					4
						5
						6
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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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

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

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

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 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	Former parent assumption of PGE tax liabilities on Non-Qualified Plan	610,028
20	Oregon tax credit related to PGE's separation from former parent	8,317,515
21	SUBTOTAL Account 211	8,890,524
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
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39		
40	TOTAL	15,302,074

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

Represents the assumption of PGE's current tax liability by Enron on taxable income related to the transfer of non-qualified plan liabilities to PGE from Portland General Holdings, recorded in 2005.

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 the Company's former parent company 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 its former parent; however, the former parent 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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	8,034,721

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	3.46% Series Due 1/14/2015 - Order No. 09-405 10/08/2009	70,000,000	455,869
25	3.81% Series Due 6/15/2017 - Order No. 09-405 10/08/2009	58,000,000	375,096
26			
27			
28	Pollution Control Bonds (Guaranteed by Company) -		
29	Port of Morrow, OR Series 1998A 5% Due 5/1/2033	23,600,000	197,390
30			243,792
31			163,270
32	City of Forsyth, MT Series 1998A 5% Due 5/1/2033	97,800,000	928,277
33	TOTAL	1,996,175,785	34,627,620

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2010/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			1,010,292
2			676,598
3	Port of St. Helens, OR Series 1985A 4.80% Due 4/1/2010	20,200,000	735,003
4	Port of St. Helens, OR Series 1985B 4.80% Due 6/1/2010	16,700,000	570,294
5			216,931
6	Port of St. Helens, OR Series 1990A 5.25% due 8/1/2014	9,600,000	386,344
7			
8	SUBTOTAL ACCOUNT 221	1,845,900,000	31,888,817
9			
10			
11			
12	ACCOUNT 224 - OTHER LONG TERM DEBT		
13			
14	Real Estate Contract Notes	156,000	
15	7.875% Notes due 3/15/2010	150,000,000	1,472,803
16			1,266,000 D
17	City of Portland Improvement District Loan	119,785	
18	SUBTOTAL ACCOUNT 224	150,275,785	2,738,803
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	1,996,175,785	34,627,620

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
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	6,265,254	11
05/26/2006	05/01/2036	05/26/2006	05/01/2036	175,000,000	11,047,746	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	7,558,242	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	2,230,254	17
						18
01/15/2009	01/15/2014	01/15/2009	01/15/2014	63,000,000	4,095,000	19
01/15/2009	01/15/2016	01/15/2009	01/15/2016	67,000,000	4,556,004	20
04/16/2009	04/15/2019	04/16/2009	04/15/2019	300,000,000	18,254,417	21
						22
11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	8,145,000	23
01/15/2010	01/14/2015	01/15/2010	01/14/2015	70,000,000	2,321,083	24
06/15/2010	06/15/2017	06/15/2010	06/15/2017	58,000,000	1,196,975	25
						26
						27
						28
5/28/1998	05/01/2033	05/28/1998	05/01/2033	23,600,000	951,610	29
		05/01/2003	05/01/2009			30
		03/03/2010	05/01/2033			31
05/28/1998	5/01/2033	05/28/1998	05/01/2033	97,800,000	3,943,357	32
				1,809,113,786	105,459,321	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.
		05/01/2003	05/01/2009			1
		03/03/2010	05/01/2033			2
04/01/1985	4/1/2010	04/01/1985	04/01/2010		242,400	3
06/01/1985	6/1/2010	06/01/1985	06/01/2010		334,000	4
		05/01/2003	05/01/2009			5
08/08/1990	8/1/2014	08/08/1990	08/01/2014	9,600,000	504,000	6
						7
				1,809,000,000	103,009,850	8
						9
						10
						11
						12
						13
05/28/2000	6/28/2010				828	14
03/13/2000	3/15/2010	03/13/2000	03/15/2010		2,448,643	15
						16
11/16/2009	11/16/2029			113,786		17
				113,786	2,449,471	18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				1,809,113,786	105,459,321	33

Schedule Page: 256 Line No.: 31 Column: c

Issue was remarketed (OPUC Order No. 09-099 dtd 03/26/2009) in March 2010, with additional issue costs of $163,270.

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

Issue was remarketed (OPUC Order No. 09-099 dtd 03/26/2009) in March 2010, with additional issue costs of $676,598.

Schedule Page: 256.1 Line No.: 17 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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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)	125,243,946
2		
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion, & Amortization	14,393,067
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Depreciation, Depletion & Amortization	15,679,346
11	Price Risk Management and Mark-To-Market	56,544,074
12	Regulatory Debits	181,120,904
13	Total Other (See Footnote)	83,951,151
14	Income Recorded on Books Not Included in Return	
15	Depreciation, Depletion & Amortization	-23,256,192
16	Price Risk Management and Mark-To-Market	-175,401,504
17	Regulatory Credits	-81,327,122
18	Miscellaneous	-7,164,452
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	-293,766,217
21	State & Local Tax Deduction	-251,128
22	Total Other (See Footnote)	-4,896,863
23		
24		
25		
26		
27	Federal Tax Net Income	-109,130,990
28	Show Computation of Tax:	
29		
30	Federal Tax Receivable for NOL Carryback	-13,466,163
31	2009 Return to Accrual Adjustment	-7,758,502
32	2007 & 2008 Audit settlement	657,823
33	Total Federal Income Tax - PGE	-20,566,842
34		
35		
36		
37		
38		
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41		
42		
43		
44		

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

Employee Benefits	$13,146,072
FAS 158 Adjustments	6,717,473
Miscellaneous	10,173,303
Travel & Entertainment	499,558
Political Activity	751,988
Federal Provision	40,708,016
State Provision	11,954,741
Total Other	$83,951,151

Schedule Page: 261 Line No.: 18 Column: b

Bad Debts	$ (351,066)
Unrealized Gain	(3,447,617)
TOLI	(1,719,343)
Miscellaneous	(1,646,426)
Total Other	$(7,164,452)

Schedule Page: 261 Line No.: 22 Column: b

Miscellaneous	$(2,779,921)
Qualified NDT	(436,490)
Employee Benefits	(1,680,452)
Total Other	$(4,896,863)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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		510,328	510,328	18,927
3	Income Tax		54,918,143	-20,566,842	-53,111,787	3,891,635
4	Foreign Insurance Excise Tax					
5	FICA (Employer Share)	823,680		17,065,045	16,735,363	
6	Unemployment	38,372		166,658	165,497	
7	Power License	1,773,577		446,343	1,077,254	-18,927
8	Superfund Tax					
9	SUBTOTAL Federal	2,741,703	54,918,143	-2,378,468	-34,623,345	3,891,635
10	State of Montana:					
11	Income Tax		196,603	-183,266	-7,718	
12	Elec. Energy Producers Tax	233,200		772,787	779,696	
13	Property Taxes	1,990,382		4,392,391	4,192,598	
14	SUBTOTAL Montana	2,223,582	196,603	4,981,912	4,964,576	
15	State of Oregon:					
16	Corp Excise Tax		56,048	284,483	100,000	17,305
17	Property Taxes		15,930,252	35,045,696	37,640,090	
18	City Taxes and Licenses	3,473,731		38,818,329	38,853,644	
19	Public Utility Comm Fees			2,948,968	2,948,968	
20	Department of Energy			1,045,308	1,624,158	
21	Department of Enviro Quality	470,830		259,600	3,900	
22	Unemployment	106,039		1,745,922	1,703,367	
23	Water Power Fee		217,688	227,324	233,404	
24	Transportation Tax	146,892		1,157,724	1,221,686	
25	Workers Comp Assessment	45,457		160,909	162,867	
26	County & City Income Tax		389,279	149,911	-100,711	261,501
27	SUBTOTAL Oregon	4,242,949	16,593,267	81,844,174	84,391,373	278,806
28	State of Washington:					
29	Property Taxes	38,400		42,733	42,733	
30	Sales Tax			3,669	3,669	
31	SUBTOTAL Washington	38,400		46,402	46,402	
32	State of Wyoming:					
33	Sales Tax					
34	SUBTOTAL Wyoming					
35	State of California:					
36	Corporate franchise tax					
37	SUBTOTAL California					
38	Canada:					
39	Goods & Services Tax					
40	SUBTOTAL Canada					
41	TOTAL	9,246,634	71,708,013	84,494,020	54,779,006	4,170,441

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
125,001					510,328	2
3,123,361	21,604,924	-20,267,757			-299,085	3
		9,200			-9,200	4
1,153,362		9,753,895			7,311,150	5
39,533		94,667			71,991	6
1,123,739					446,343	7
						8
5,564,996	21,604,924	-10,409,995			8,031,527	9
						10
7,718	379,869	-191,313			8,047	11
226,291		451,197			321,590	12
2,190,175		3,869,903			522,488	13
2,424,184	379,869	4,129,787			852,125	14
						15
45,740	-100,000	139,108			145,375	16
	18,524,646	33,183,881			1,861,815	17
3,438,624	208	38,818,329				18
					2,948,968	19
	578,850	1,194,209			-148,901	20
726,530					259,600	21
148,594		991,741			754,181	22
	223,768				227,324	23
82,930		1,138,352			19,372	24
43,499		91,402			69,507	25
122,644	-200	177,590			-27,679	26
4,608,561	19,227,272	75,734,612			6,109,562	27
						28
38,400		42,733				29
					3,669	30
38,400		42,733			3,669	31
						32
						33
						34
						35
						36
						37
						38
						39
						40
12,636,141	41,212,065	69,497,137			14,996,883	41

Schedule Page: 262 Line No.: 2 Column: f

Transfer accrued balance from Power License $18,927

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

Intercompany tax consolidation with subsidiaries $186,638
Transfer to APIC for restricted stock unit vesting $6,346
Reclassification of deferred taxes $2,479,983
Federal tax return examination interest accrual $1,218,668

Schedule Page: 262 Line No.: 7 Column: f

Transfer accrued balance to Annual FERC Charges-Sales for Resale ($18,927)

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

Intercompany tax consolidation with subsidiaries $45,740
Reclassification for various tax position adjustments ($28,435)

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

Intercompany tax consolidation with subsidiaries $21,933
Reclassification for various tax position adjustments $239,568

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	61,995			420	47,943	
6							
7							
8	TOTAL	61,995				47,943	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
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46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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
14,052	See Note		5
			6
			7
14,052			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
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			40
			41
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			47
			48

Schedule Page: 266 Line No.: 5 Column: i

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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)	62,749	Various	4,956	7,861	65,654
2						
3	Accelerated cost recovery system					
4	tax benefit sale - amort. over					
5	service lives of related					
6	property	296,289	421	36,299		259,990
7						
8	Reserve for Boardman Interest	1,229,780	456	1,276,262	46,482	
9						
10	Deferred Liability for Transferred					
11	Non-Qualified Plan Benefits	1,006,849	421	80,464		926,385
12						
13	Deferred premiums on power					
14	options sold		555	538,650	538,650	
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
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33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	2,595,667		1,936,631	592,993	1,252,029

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

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

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

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

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
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							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	404,960,313	118,519,300	6,318,634
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	404,960,313	118,519,300	6,318,634
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	404,960,313	118,519,300	6,318,634
10	Classification of TOTAL			
11	Federal Income Tax	341,060,930	97,742,867	5,210,977
12	State Income Tax	57,027,992	19,021,162	1,014,078
13	Local Income Tax	6,871,391	1,755,271	93,579

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

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
	21,209			190, 182.3	2,539,592	519,679,362	2
							3
							4
	21,209				2,539,592	519,679,362	5
							6
							7
							8
	21,209				2,539,592	519,679,362	9
							10
	17,491				-4,995,759	428,579,570	11
	3,404				8,371,668	83,403,340	12
	314				-836,317	7,696,452	13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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 & Amortization	40,114,338		
4	Price Risk Management	127,644,677	127,032,474	89,010,977
5	Regulatory Contingencies	14,362,612	11,916,769	3,768,974
6	Asset Retirement Obligation	11,110,208	1,247,967	
7	Other	79,457,088	11,439,211	8,106,640
8				
9	TOTAL Electric (Total of lines 3 thru 8)	272,688,923	151,636,421	100,886,591
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	2,105,640	469,026	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	274,794,563	152,105,447	100,886,591
20	Classification of TOTAL			
21	Federal Income Tax	231,434,728	125,441,362	83,201,172
22	State Income Tax	38,710,310	24,411,403	16,191,289
23	Local Income Tax	4,649,525	2,252,682	1,494,130

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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					
		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
				190	2,015,064	42,129,402	3
		283	90,080,732			75,585,442	4
747,460	302,106	190	7,409,551	190/283	93,452,441	108,998,651	5
						12,358,175	6
2,065		190/219/	4,422,778	190/219/	14,407,700	92,776,646	7
							8
749,525	302,106		101,913,061		109,875,205	331,848,316	9
							10
							11
							12
							13
							14
							15
							16
							17
1,395,469	276,733			190	1,666,660	5,360,062	18
2,144,994	578,839		101,913,061		111,541,865	337,208,378	19
							20
1,768,977	477,368		84,047,702		87,176,922	278,095,747	21
344,250	92,898		16,356,027		23,292,823	54,118,572	22
31,767	8,573		1,509,332		1,072,117	4,994,056	23

NOTES (Continued)

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

	Balance at Beginning of Year	Balance at End of Year
Power Cost Adjustment	$ (675,694)	$ -
Biglow Revenue Requirement	4,145,626	8,999,086
Boardman Power Cost Deferral	6,086,696	0
Decoupling - SNA Deferral	(1,773,615)	4,821,600
FAS 71 Mark-to-Market	0	71,601,429
Miscellaneous	6,579,599	23,576,536
Total Other	$ 14,362,612	$108,998,651

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

	Balance at Beginning of Year	Balance at End of Year
Employee Benefits	$ 69,826,298	$ 85,628,813
Other	9,630,790	7,147,833
Total Other	$ 79,457,088	$ 92,776,646

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

	Balance at Beginning of Year	Balance at End of Year
TOLI Gain/Loss	$ 2,575,762	$ 3,970,594
Other	(470,122)	1,389,465
Total Other	$ 2,105,640	$ 5,360,059

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	8,744,196	191	306,031	191,723	8,629,888
2		7,979,683	283	199,805	293,653	8,073,531
3						
4	Deferred Taxes on Investment Tax Credits	24,179	190	20,018		4,161
5		15,457	283	12,743		2,714
6						
7	Surplus CAA Allowances	666,538			5,762	672,300
8	(per Order No. 552 dtd 3/31/1993)					
9						
10	Gain on Asset Sales	2,178,733	407.4	(15,687)	337,320	2,531,740
11	(per OPUC Order No. 01-777 dtd 8/31/2001)					
12						
13	Interest on Portland Energy Solutions Note	221,906			19,098	241,004
14	(per OPUC Order No. 02-280 dtd 4/19/2002)					
15						
16	Asset Retirement Obligations - Balancing Account	29,817,472			3,375,518	33,192,990
17						
18	Williams Settlement	38,752	229	39,869	1,117	
19	(per OPUC Order No. 04-286 dtd 4/19/2004)					
20						
21	Power Cost Adjustment (Oct 2001 - Dec 2002)	1,807,992			78,731	1,886,723
22	(per OPUC Order No. 04-293 dtd 5/24/2004)					
23						
24	Coyote Springs Major Maintenance Accrual	5,809,397	407.3	2,683,748	2,044,271	5,169,920
25	(per OPUC Order No. 01-777 dtd 8/31/2001)					
26						
27	ISFSI Pollution Control Tax Credit Deferral	17,121,153	407.3	1,076,140	5,595,466	21,640,479
28	(per OPUC Order No. 05-136 dtd 3/15/2005)					
29						
30	Category A Advertising Deferral (Year 1)	1,783	229	1,834	51	
31	(per OPUC Order No. 01-777 dtd 8/31/2001)					
32						
33	Energy Efficiency Programs' Residual	143,897	229	148,044	4,147	
34	(per Advice No. 05-19 dtd 12/20/2005)					
35						
36	Zero Interest Program Loan Repayments	754,146			154,354	908,500
37	(per Advice No. 05-19 dtd 12/20/2005)					
38						
39						
40	BPA Subscription Power - Balancing Account	9,494,447	456	50,928,888	45,138,006	3,703,565
41	TOTAL	106,446,062		73,783,779	59,848,186	92,510,469

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	(per OPUC Order No. 08-175 dtd 3/20/2008)	1,936,013			(56,193)	1,879,820
2						
3	Power Cost Adjustment Mechanism	1,047,717	456	1,118,929	22,914	-48,298
4	(per OPUC Order No. 07-015 dtd 1/12/2007)					
5						
6	Conservation Investment Assets	80,777	229	83,114	2,337	
7						
8	Prior Tax Benefits Recoverable	19,882	229	19,882		
9	(per OPUC Order No. 00-601 dtd 9/29/2000)					
10						
11	Schedule 110 EE - Asset Bal Acct				343,128	343,128
12	(per Advice No. 07-25 dtd 5/20/2008)					
13						
14	Old Meters - Balancing Acct	4,790,881	407.3	4,790,881		
15	(per OPUC Order No. 08-245 dtd 5/5/2008)					
16						
17	SB1149 Residual Balance	1,402,050	407.4		61,054	1,463,104
18	(per OPUC Order No. 00-038 dtd 1/24/2000;					
19	amrt. over 5 years beg. 1/1/2004)					
20						
21	Trojan Decom Asset Balancing Acct	12,349,011	182.3	12,349,011		
22						
23	Direct Access Open Enrollment Deferral - 2010				1,328,450	1,328,450
24	(per Advice 10-22A dtd 12/28/2010)					
25						
26	Sunway 3 Investment Deferral		407.4	20,529	907,279	886,750
27	(per UM 1480 dtd 4/01/2010;					
28	amortization over 20 years)					
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	106,446,062		73,783,779	59,848,186	92,510,469

Schedule Page: 278 Line No.: 18 Column: c

The residual balance was offset against an OPUC regulatory fee refund pursuant to OPUC Order No. 10-372, dated September 22, 2010.

Schedule Page: 278 Line No.: 27 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. 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. PGE determined $1.076 million are not expected to be used; accordingly, the deferred balance was reduced, with a corresponding decrease to expense FERC 407.3-Regulatory Debits.

Schedule Page: 278 Line No.: 30 Column: c

The residual balance was offset against an OPUC regulatory fee refund pursuant to OPUC Order No. 10-372, dated September 22, 2010.

Schedule Page: 278 Line No.: 33 Column: c

The residual balance was offset against an OPUC regulatory fee refund pursuant to OPUC Order No. 10-372, dated September 22, 2010.

Schedule Page: 278.1 Line No.: 6 Column: c

The residual balance was offset against an OPUC regulatory fee refund pursuant to OPUC Order No. 10-372, dated September 22, 2010.

Schedule Page: 278.1 Line No.: 8 Column: c

The residual balance was offset against an OPUC regulatory fee refund pursuant to OPUC Order No. 10-372, dated September 22, 2010.

Schedule Page: 278.1 Line No.: 11 Column: e

Reclassified Regulatory Asset credit balance to Regulatory Liability.

Schedule Page: 278.1 Line No.: 21 Column: c

Pursuant to OPUC Order No. 10-051, dated February 11, 2010, the deferred accrued savings on decommissioning activities at PGE's closed Trojan Nuclear Plant were offset with the remaining deferred regulatory asset balance for the incremental power costs incurred by PGE during the 2005-2006 Boardman outage.

Schedule Page: 278.1 Line No.: 26 Column: f

Deferral represents reductions in the SunWay 3 solar facility related to Clean Wind Development Funds allocated to the project and a developer fee.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	752,908,496	793,811,727
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	578,272,535	607,511,065
5	Large (or Ind.) (See Instr. 4)	219,992,392	160,556,586
6	(444) Public Street and Highway Lighting	17,783,471	17,850,491
7	(445) Other Sales to Public Authorities	6,133	6,088
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,568,963,027	1,579,735,957
11	(447) Sales for Resale	239,352,251	274,168,670
12	TOTAL Sales of Electricity	1,808,315,278	1,853,904,627
13	(Less) (449.1) Provision for Rate Refunds	-24,749,212	-385,092
14	TOTAL Revenues Net of Prov. for Refunds	1,833,064,490	1,854,289,719
15	Other Operating Revenues		
16	(450) Forfeited Discounts	653,441	785,251
17	(451) Miscellaneous Service Revenues	2,184,731	1,801,406
18	(453) Sales of Water and Water Power	-14,835	44,968
19	(454) Rent from Electric Property	6,970,988	6,646,519
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	87,170,062	95,993,713
22	(456.1) Revenues from Transmission of Electricity of Others	5,717,012	6,416,170
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	102,681,399	111,688,027
27	TOTAL Electric Operating Revenues	1,935,745,889	1,965,977,746

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
7,452,448	7,900,585	717,719	714,377	2
				3
6,834,926	7,043,916	102,033	100,973	4
3,285,576	2,363,991	265	271	5
110,041	110,646	248	247	6
74	74	1	1	7
				8
				9
17,683,065	17,419,212	820,266	815,869	10
6,803,712	7,553,992	47	47	11
24,486,777	24,973,204	820,313	815,916	12
				13
24,486,777	24,973,204	820,313	815,916	14

Line 12, column (b) includes $ -7,787,000 of unbilled revenues.

Line 12, column (d) includes -45,384 MWH relating to unbilled revenues

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

Includes $7,246,416 in revenue related to the delivery of 331,843 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 2010, 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 $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(e).

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

Includes a $2,601,778 in revenue related to the delivery of 717,596 megawatt hours to customers of Electricity Services Suppliers (ESSs). For 2010, 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.: 5 Column: c

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 (e).

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

Miscellaneous Service Revenues include charges billed in accordance with PGE Tariff Schedule 300 C*harges as Defined by the Rules and Regulations and Miscellaneous Charges* and Schedule 320 *Meter Information Services*. Schedule 300 charges recorded to this account include the following:

Returned Payment Charges
Reconnect Charges
Field Service Charges
Meter Tamper Charges
Meter Test Charges
Meter Verification Charges
Switching Fees

This note applies to line 17, columns (b) and (c).

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

Other Electric Revenues consist of the following:

	2010	2009
BPA Subscription Power - Balancing Account	$50,928,888	$53,259,875
Biglow Canyon Phase 2 Deferral	(6,253,583)	10,629,811
Biglow Canyon Phase 3 Deferral	17,763,375	-

Residential Sch 123 SNA Deferral	4,002,593	(6,024,245)
Small Nonresidential Sch 123 SNA Deferral	1,830,290	1,476,514
Sch 123 LRRA Deferral	-	(500,000)
Power Cost Adjustment Mechanism	1,118,929	18,226,822
Boardman Power Cost Deferral	1,276,262	-
Meter Information Services	-	385,283
EE Program Delivery Contractor Services	1,457,297	-
PGE Share of Boardman Ash Sales	382,423	556,801
Income from Salmon Springs Hospitality Group	346,613	333,071
Park Revenues	500,395	-
Steam Sales	1,747,435	2,098,201
Gas for Resale	405,903	-
Oil for Resale	5,147,422	7,568,007
Sales for Resale	5,390,250	6,548,910
Other - net	1,125,570	1,434,663
Totals	$87,170,062	$95,993,713

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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33					
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35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	7,495,419	756,229,796	715,308	10,479	0.1009
3	9 Stable Rate Pilot	24,715	2,551,446	2,411	10,251	0.1032
4	15 Outdoor Area Lighting	6,880	1,510,254			0.2195
5	Residential Unbilled Revenue	-74,566	-7,383,000			0.0990
6	TOTAL Account 440	7,452,448	752,908,496	717,719	10,384	0.1010
7						
8	General Comm. and Ind. Sales:					
9	9 Stable Rate Pilot	1,557	167,344	67	23,239	0.1075
10	15 Comm. Outdoor Lighting	16,250	2,733,061			0.1682
11	32 Small Nonresidential	1,472,134	147,363,971	85,664	17,185	0.1001
12	38 Optional Time of Day -	28,175	2,951,937	270	104,352	0.1048
13	Large Nonresidential					
14	47 Irrigation - Drainage - Small	17,788	2,100,652	2,052	8,669	0.1181
15	49 Irrigation - Drainage - Large	52,161	4,170,706	965	54,053	0.0800
16	83-S Large Nonresidential	4,764,108	376,538,536	12,710	374,831	0.0790
17	85-S Large Nonresidential	12,979	1,004,963	11	1,179,909	0.0774
18	89-S Large Nonresidential	511,814	38,587,394	83	6,166,434	0.0754
19	483-S COS Opt-Out - Lrg. Nonresid	642	40,934	1	642,000	0.0638
20	483-S COS Opt-Out - Lrg. Nonresid		176,808	16		
21	489-S COS Opt-Out - Lrg. Nonresid	11,360	572,621	1	11,360,000	0.0504
22	489-S COS Opt-Out - Lrg. Nonresid		195,987	5		
23	532 DAS - Small Nonresidential		28,324	11		
24	583-S DAS - Large Nonresidential		6,497,243	174		
25	589-S DAS - Large Nonresidential		362,054	3		
26	Gen Comm. & Ind. Unbilled Revenue	-54,042	-5,220,000			0.0966
27	TOTAL Account 442 - Small	6,834,926	578,272,535	102,033	66,987	0.0846
28						
29	Large Industrial Power Sales:					
30	75 Partial Requirements Service	177,157	9,198,465	1	177,157,000	0.0519
31	83-T Large Nonresidential					
32	83-P Large Nonresidential	317,433	23,188,255	155	2,047,955	0.0730
33	89-T Large Nonresidential	384,881	24,646,299	7	54,983,000	0.0640
34	89-P Large Nonresidential	2,322,746	156,246,595	90	25,808,289	0.0673
35	483-P COS Opt-Out - Lg. Nonresid		6,348			
36	489-T COS Opt-Out - Lg. Nonreside		931,285	2		
37	489-P COS Opt-Out - Lg. Nonreside		163,100	7		
38	583-T DAS - Large Nonresidential					
39	583-P DAS - Large Nonresidential		96,402	1		
40	589-P DAS - Large Nonresidential		677,643	2		
41	TOTAL Billed	17,728,449	1,576,750,027	820,266	21,613	0.0889
42	Total Unbilled Rev.(See Instr. 6)	-45,384	-7,787,000	0	0	0.1716
43	TOTAL	17,683,065	1,568,963,027	820,266	21,558	0.0887

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	Large Industrial Unbilled Revenue	83,359	4,838,000			0.0580
2	TOTAL Account 442 - Large	3,285,576	219,992,392	265	12,398,400	0.0670
3						
4	Various Public Street and					
5	Highway Lighting:					
6	Street Lighting	110,176	17,805,471	248	444,258	0.1616
7	Street Lighting Unbilled Rev	-135	-22,000			0.1630
8	TOTAL Account 444	110,041	17,783,471	248	443,714	0.1616
9						
10	Other Sales to Public Authorities					
11	Communication Devices Electr	74	6,133	1	74,000	0.0829
12	TOTAL Account 445	74	6,133	1	74,000	0.0829
13						
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41	TOTAL Billed	17,728,449	1,576,750,027	820,266	21,613	0.0889
42	Total Unbilled Rev.(See Instr. 6)	-45,384	-7,787,000	0	0	0.1716
43	TOTAL	17,683,065	1,568,963,027	820,266	21,558	0.0887

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. In 2010, this customer purchased its energy from PGE.

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

Rate Schedule 483 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. PGE continues to serve these customers by delivering the energy purchased from ESSs.

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. In 2010, this customer purchased its energy from PGE.

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

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

Schedule Page: 304 Line No.: 22 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.: 23 Column: a

Rate Schedule 532 complete title: Small 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 583 complete title: Large Nonresidential 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.: 25 Column: a

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

Schedule Page: 304 Line No.: 25 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.: 35 Column: a

Rate Schedule 483 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 489 complete title: Large Nonresidential (>1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 37 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.: 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 583 complete title: Large Nonresidential 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.

Schedule Page: 304 Line No.: 40 Column: a

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

Schedule Page: 304 Line No.: 40 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.

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	RQ SALES:					
2	Fale Safe Corporation	RQ	PGE-1	75	75	75
3						
4						
5	NON-RQ SALES:					
6	Avista Corp	SF	WSPP-1	NA	NA	NA
7	BNP Paribas Energy	SF	WSPP-1	NA	NA	NA
8	Barclays Bank	SF	WSPP-1	NA	NA	NA
9	Black Hills Power	SF	WSPP-1	NA	NA	NA
10	Bonneville Power Administratio	SF	WSPP-1	NA	NA	NA
11	BP Energy Company	SF	WSPP-1	NA	NA	NA
12	Burbank, City of	SF	WSPP-1	NA	NA	NA
13	California Independent System	SF	WSPP-1	NA	NA	NA
14	Calpine Energy Services	SF	PGE-11	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:
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	Cargill Alliant LLC	SF	WSPP-1	NA	NA	NA
2	Chelan County, PUD No. 1, Was	SF	WSPP-1	NA	NA	NA
3	Clatskanie County PUD, Washing	SF	WSPP-1	NA	NA	NA
4	Conoco Phillips	SF	WSPP-1	NA	NA	NA
5	Constellation Energy Commoditi	SF	PGE-11	NA	NA	NA
6	EDF Trading NA	SF	WSPP-1	NA	NA	NA
7	Endure Energy, LLC	SF	WSPP-1	NA	NA	NA
8	Enmax	SF	PGE-11	NA	NA	NA
9	Epcor Energy Marketing	SF	WSPP-1	NA	NA	NA
10	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
11	Glendale, City of	LF	PGE-78	19	19	19
12	Glendale, City of	SF	WSPP-1	NA	NA	NA
13	Grant County, PUD No. 2, Wash	SF	WSPP-1	NA	NA	NA
14	Iberdrola Renewables	SF	PGE-11	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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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)	Average Monthly CP Demand (f)
1	Idaho Power Company	SF	WSPP-1	NA	NA	NA
2	J. Aron Company	SF	PGE-11	NA	NA	NA
3	JP Morgan Ventures	SF	WSPP-1	NA	NA	NA
4	Load Balance Energy	OS	OATT	NA	NA	NA
5	Los Angeles Depart Water Pow	SF	WSPP-1	NA	NA	NA
6	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
7	Mirant Americas Energy Marketi	SF	PGE-11	NA	NA	NA
8	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
9	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
10	NaturEner Power Watch, LLC	SF	WSPP-1	NA	NA	NA
11	Northern California Power Age	SF	WSPP-1	NA	NA	NA
12	NorthPoint Energy Solutions	SF	WSPP-1	NA	NA	NA
13	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
14	Okanogan County PUD, Washingto	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:
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	Pacific Gas & Electric Company	SF	WSPP-1	NA	NA	NA
2	Pacific Northwest Generating C	SF	WSPP-1	NA	NA	NA
3	PacifiCorp	LU	PGE-11	NA	NA	NA
4	PacifiCorp	SF	PGE-11	NA	NA	NA
5	Powerex	SF	PGE-11	NA	NA	NA
6	PPL Energy Plus	SF	PGE-11	NA	NA	NA
7	Public Service of Colorado	SF	WSPP-1	NA	NA	NA
8	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
9	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
10	Redding, City of	SF	WSPP-1	NA	NA	NA
11	Roseville, City of	SF	WSPP-1	NA	NA	NA
12	Sacramento Municipal Utility D	SF	WSPP-1	NA	NA	NA
13	San Diego Gas & Electric Compa	SF	WSPP-1	NA	NA	NA
14	Seattle City Light	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:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sempra Corporation	SF	WSPP-1	NA	NA	NA
2	Shell Energy NA	SF	WSPP-1	NA	NA	NA
3	Sierra Pacific	SF	WSPP-1	NA	NA	NA
4	Silicon Valley Power	SF	WSPP-1	NA	NA	NA
5	Snohomish County, PUD No.1, Wa	SF	WSPP-1	NA	NA	NA
6	Southern California Edison	SF	PGE-11	NA	NA	NA
7	Tacoma, City of	SF	WSPP-1	NA	NA	NA
8	The Energy Authority	SF	WSPP-1	NA	NA	NA
9	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
10	TransCanada Power	SF	WSPP-1	NA	NA	NA
11	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
12	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
13						
14	Direct Access Deferral - 2010			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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Biglow 3 Test Energy Sales			NA	NA	NA
2	Direct Access Amortization - 2009			NA	NA	NA
3						
4	Portland General Electric Company	SF	OA96137	428	NA	NA
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	-513,299		226,792	2
					3
					4
					5
6,883		228,158		228,158	6
76,800		1,423,222		1,423,222	7
52,531		1,879,312		1,879,312	8
317		11,880		11,880	9
262,537		11,779,197		11,779,197	10
124,797		4,309,771		4,309,771	11
56,691		1,237,755		1,237,755	12
218,048		6,945,751		6,945,751	13
458,502		20,845,849		20,845,849	14
0	740,091	-513,299	0	226,792	
6,813,605	8,311,392	231,983,495	-1,169,428	239,125,459	
6,813,605	**9,051,483**	**231,470,196**	**-1,169,428**	**239,352,251**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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.
51,873		1,791,363		1,791,363	1
4,000		146,600		146,600	2
454		15,320		15,320	3
16,400		582,470		582,470	4
77,379		2,470,734		2,470,734	5
117,684		3,935,964		3,935,964	6
4,400		136,750		136,750	7
675		32,270		32,270	8
15,627		638,134		638,134	9
157,921		437,644		437,644	10
62,378	5,480,000	2,007,534		7,487,534	11
10,471		324,558		324,558	12
58,086		1,575,849		1,575,849	13
826,172		26,328,536		26,328,536	14
0	740,091	-513,299	0	226,792	
6,813,605	8,311,392	231,983,495	-1,169,428	239,125,459	
6,813,605	**9,051,483**	**231,470,196**	**-1,169,428**	**239,352,251**	

Name of Respondent Portland General Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/30/2012	Year/Period of Report End of 2010/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.
30,307		1,118,596		1,118,596	1
16,799		664,284		664,284	2
31,300		1,301,242		1,301,242	3
39,286			1,217,798	1,217,798	4
19,794		625,316		625,316	5
117,512		4,061,447		4,061,447	6
12,000		425,155		425,155	7
8,512		317,201		317,201	8
312,932		10,670,776		10,670,776	9
	95,239			95,239	10
5,715		173,475		173,475	11
375		10,750		10,750	12
214,337		6,765,684		6,765,684	13
250		10,400		10,400	14
0	740,091	-513,299	0	226,792	
6,813,605	8,311,392	231,983,495	-1,169,428	239,125,459	
6,813,605	**9,051,483**	**231,470,196**	**-1,169,428**	**239,352,251**	

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.
6,160		158,075		158,075	1
11,319		227,195		227,195	2
17,003			85,378	85,378	3
53,251		1,716,859		1,716,859	4
199,935		5,537,217		5,537,217	5
622,881		21,933,170		21,933,170	6
73,600		3,077,628		3,077,628	7
291,316		9,884,649		9,884,649	8
20,730		839,785		839,785	9
3,160		124,563		124,563	10
85		3,720		3,720	11
90,344		2,976,931		2,976,931	12
3,693		169,706		169,706	13
17,502		538,511		538,511	14
0	740,091	-513,299	0	226,792	
6,813,605	8,311,392	231,983,495	-1,169,428	239,125,459	
6,813,605	**9,051,483**	**231,470,196**	**-1,169,428**	**239,352,251**	

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.
299,038		10,252,809		10,252,809	1
167,876		5,419,822		5,419,822	2
12,151		417,894		417,894	3
22,626		843,621		843,621	4
5,970		214,710		214,710	5
9,931		373,594		373,594	6
1,353		46,439		46,439	7
3,876		135,081		135,081	8
1,334,603		49,431,330		49,431,330	9
35,636		1,389,271		1,389,271	10
19,202		663,092		663,092	11
10,726		368,216		368,216	12
					13
			-1,274,364	-1,274,364	14
0	740,091	-513,299	0	226,792	
6,813,605	8,311,392	231,983,495	-1,169,428	239,125,459	
6,813,605	**9,051,483**	**231,470,196**	**-1,169,428**	**239,352,251**	

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.
			-381,082	-381,082	1
			-817,158	-817,158	2
					3
9,893	2,736,153	10,660		2,746,813	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	740,091	-513,299	0	226,792	
6,813,605	8,311,392	231,983,495	-1,169,428	239,125,459	
6,813,605	**9,051,483**	**231,470,196**	**-1,169,428**	**239,352,251**	

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.: 11 Column: b

The contract with the City of Glendale expires on 9/30/12.

Schedule Page: 310.2 Line No.: 4 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.: 3 Column: j

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

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

Defer costs associated with the implementation of the 2010 annual direct access open enrollment window. See Tariff Schedule 128 filed 01/26/2007.

Schedule Page: 310.5 Line No.: 1 Column: j

Biglow 3 Wind test energy sales reclassified to capital.

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

Amortization of deferred costs associated with the implementation of the 2009 annual direct access open enrollment window. See Tariff Schedule 128 filed 01/26/2007.

Schedule Page: 310.5 Line No.: 4 Column: a

Represents Portland General Electric Company's 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.

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	8,899,536	9,760,084
5	(501) Fuel	72,804,356	55,400,250
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	1,637,763	1,316,006
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	83,341,655	66,476,340
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	16,632,220	16,447,006
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant	25,007	64,643
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	16,657,227	16,511,649
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	99,998,882	82,987,989
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	1,623,351	5,026,730
45	(536) Water for Power	217,685	207,432
46	(537) Hydraulic Expenses	2,668,682	2,434,954
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,971,169	1,800,000
49	(540) Rents	-788,349	1,354,509
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	5,692,538	10,823,625
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	4,741,648	3,101,342
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	779,749	1,049,706
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	5,521,397	4,151,048
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	11,213,935	14,974,673

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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	6,383,378	7,402,333
63	(547) Fuel	270,356,987	287,861,571
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses	6,301,942	5,446,491
66	(550) Rents	498,277	573,138
67	TOTAL Operation (Enter Total of lines 62 thru 66)	283,540,584	301,283,533
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	20,648,614	19,398,734
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	61,877	124,007
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	20,710,491	19,522,741
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	304,251,075	320,806,274
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	570,657,683	680,506,141
77	(556) System Control and Load Dispatching	2,514,903	2,854,993
78	(557) Other Expenses	15,138,169	9,935,927
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	588,310,755	693,297,061
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,003,774,647	1,112,065,997
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,468,042	2,750,992
84	(561) Load Dispatching	848	811
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	669,855	605,073
87	(561.3) Load Dispatch-Transmission Service and Scheduling	819,387	790,802
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	137,283	41,710
90	(561.6) Transmission Service Studies	38,791	377
91	(561.7) Generation Interconnection Studies	217,923	159,266
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	22,579	24,494
94	(563) Overhead Lines Expenses		
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	69,074,968	65,753,799
97	(566) Miscellaneous Transmission Expenses	2,746,813	2,282,200
98	(567) Rents	2,478,805	2,190,281
99	TOTAL Operation (Enter Total of lines 83 thru 98)	78,675,294	74,599,805
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	1,651,142	1,499,921
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	896,032	1,064,374
108	(571) Maintenance of Overhead Lines	1,701,485	1,567,827
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,248,659	4,132,122
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	82,923,953	78,731,927

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	8,784,660	9,161,480
135	(581) Load Dispatching		
136	(582) Station Expenses	786,784	669,254
137	(583) Overhead Line Expenses		
138	(584) Underground Line Expenses	1,792,761	1,879,710
139	(585) Street Lighting and Signal System Expenses	2,817,136	3,000,785
140	(586) Meter Expenses	965,402	1,018,648
141	(587) Customer Installations Expenses	1,855,477	1,428,803
142	(588) Miscellaneous Expenses	406,678	510,836
143	(589) Rents	1,543,349	1,454,888
144	TOTAL Operation (Enter Total of lines 134 thru 143)	18,952,247	19,124,404
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,250,966	1,328,734
147	(591) Maintenance of Structures	196,069	297,091
148	(592) Maintenance of Station Equipment	2,767,823	3,301,099
149	(593) Maintenance of Overhead Lines	27,850,887	29,353,802
150	(594) Maintenance of Underground Lines	5,115,498	4,304,246
151	(595) Maintenance of Line Transformers		
152	(596) Maintenance of Street Lighting and Signal Systems		
153	(597) Maintenance of Meters	89,108	27,947
154	(598) Maintenance of Miscellaneous Distribution Plant	11,417,558	10,586,489
155	TOTAL Maintenance (Total of lines 146 thru 154)	48,687,909	49,199,408
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	67,640,156	68,323,812
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	-536,169	3,667,722
161	(903) Customer Records and Collection Expenses	38,200,576	39,307,626
162	(904) Uncollectible Accounts	6,491,987	9,267,650
163	(905) Miscellaneous Customer Accounts Expenses	4,198,250	4,534,934
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	48,354,644	56,777,932

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	8,220,350	6,951,629
169	(909) Informational and Instructional Expenses	2,352,508	2,359,133
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	10,572,858	9,310,762
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	41,010,361	35,469,748
182	(921) Office Supplies and Expenses	21,689,380	17,920,489
183	(Less) (922) Administrative Expenses Transferred-Credit	12,228,681	11,724,879
184	(923) Outside Services Employed	5,998,386	5,268,084
185	(924) Property Insurance	4,214,250	5,482,755
186	(925) Injuries and Damages	7,574,002	4,604,939
187	(926) Employee Pensions and Benefits	43,339,260	40,345,378
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	6,248,074	7,853,865
190	(929) (Less) Duplicate Charges-Cr.	1,927,695	2,028,712
191	(930.1) General Advertising Expenses	1,504,649	1,219,309
192	(930.2) Miscellaneous General Expenses	6,365,159	4,809,496
193	(931) Rents	4,102,804	4,251,175
194	TOTAL Operation (Enter Total of lines 181 thru 193)	127,889,949	113,471,647
195	Maintenance		
196	(935) Maintenance of General Plant	1,426,255	1,608,301
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	129,316,204	115,079,948
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,342,582,462	1,440,290,378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Arizona Public	SF	WSPP-1	NA	NA	NA
2	Avista Corp. - AVWP (was WWP)	SF	WSPP-1	NA	NA	NA
3	BNP Paribas Energy	SF	WSPP-1	NA	NA	NA
4	Barclays Bank PLC - BARC	SF	WSPP-1	NA	NA	NA
5	Black Hills Power	SF	WSPP-1	NA	NA	NA
6	Bonneville Power Administration	SF	92375	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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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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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)	Average Monthly CP Demand (f)
1	Clatskanie County PUD	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	EDF Trading North America, LLC	SF	WSPP-1	NA	NA	NA
10	Endure Energy, LLC	SF	WSPP-1	NA	NA	NA
11	Enmax	SF	WSPP-1	NA	NA	NA
12	ESI Vansycle Partners, LP	LF	WSPP-1	NA	NA	NA
13	Eugene Water & Electric Board	LF	WSPP-1	10	10	10
14	Eugene Water & Electric Board	OS	ER94-717	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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
2	Eugene Water & Electric Board	EX	WSPP-1	NA	NA	NA
3	Glendale, City of	SF	WSPP-1	NA	NA	NA
4	Glendale, City of	EX	PGE-78	NA	NA	NA
5	Grant County, PUD No. 2, Washington	LU	Wanapum	NA	NA	NA
6	Grant County, PUD No. 2, Washington	LU	Priest Rapids	NA	NA	NA
7	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
8	Iberdrola Renewables	SF	WSPP-1	NA	NA	NA
9	Iberdrola Renewables	LF	WSPP-1	NA	NA	NA
10	Idaho Power Company	SF	WSPP-1	NA	NA	NA
11	J. Aron Company	SF	PGE-11	NA	NA	NA
12	JP Morgan Ventures	SF	WSPP-1	NA	NA	NA
13	Load Balance Energy	OS	OATT	NA	NA	NA
14	Los Angeles Depart Water Power	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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
2	Mirant Americas Energy Marketing	SF	WSPP-1	NA	NA	NA
3	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
4	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
5	Morgan Stanley Capital Group	LF	PGE-11	NA	NA	NA
6	NaturEner Power Watch	SF	WSPP-1	NA	NA	NA
7	Northern California Power Agency	SF	WSPP-1	NA	NA	NA
8	NorthPoint Energy Solutions Inc	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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	PaTu Wind	LF	WSPP-1	NA	NA	NA
2	Portland, City of	LU	#2821	NA	NA	NA
3	Portland, City of	LU	QF83-448	NA	NA	NA
4	Powerex	SF	PGE-11	NA	NA	NA
5	PPL Energy Plus	SF	PGE-11	NA	NA	NA
6	Public Service Company of Colorado	SF	WSPP-1	NA	NA	NA
7	Public Service Company of New Mexico	SF	WSPP-1	NA	NA	NA
8	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
9	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
10	Redding, City of	SF	WSPP-1	NA	NA	NA
11	Roseville, City of	SF	WSPP-1	NA	NA	NA
12	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
13	San Diego Gas & Electric Company	SF	WSPP-1	NA	NA	NA
14	Seattle City Light	SF	WSPP-1	NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Sempra Corporation	SF	WSPP-1	NA	NA	NA
2	Shell Energy	SF	WSPP-1	NA	NA	NA
3	Sierra Pacific	SF	WSPP-1	NA	NA	NA
4	Silicon Valley Power	SF	WSPP-1	NA	NA	NA
5	Snohomish County, PUD No. 1, Washingt	SF	WSPP-1	NA	NA	NA
6	Southern California Edison	SF	PGE-11	NA	NA	NA
7	Spokane Energy, LLC	LF	PGE-82	144	144	144
8	Spokane Energy, LLC	EX	PGE-82	NA	NA	NA
9	Tacoma, City of	SF	WSPP-1	NA	NA	NA
10	The Energy Authority	SF	WSPP-1	NA	NA	NA
11	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
12	TransAlta Energy Marketing	LF	PGE-11	NA	NA	NA
13	TransCanada Energy Marketing	SF	WSPP-1	NA	NA	NA
14	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
	Total					

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

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1	Warm Springs Power Enterprises	LF	WSPP-1	NA	NA	NA
2	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
3	Lake Oswego Corporation	LU	201	NA	NA	NA
4	Douglas Pegar	OS	201	NA	NA	NA
5	Domaine Drouhin	OS	201	NA	NA	NA
6	Von Land Co	OS	201	NA	NA	NA
7	Minikahada Hydropower Co	OS	201	NA	NA	NA
8	SunWay LLC	OS	201	NA	NA	NA
9	Solar Feed-In	OS	205	NA	NA	NA
10	Tualatin Valley Water Dist	OS	201	NA	NA	NA
11	Oregon Heat	OS	203	NA	NA	NA
12	Load Curtailment Program			NA	NA	NA
13	Margin on Electric Financials			NA	NA	NA
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Reserve Trading Credit Risk			NA	NA	NA
2	Green Power			NA	NA	NA
3						
4	Non-cash exchanges					
5						
6						
7						
8						
9						
10						
11						
12						
13						
14	Footnote					
	Total					

Name of Respondent Portland General Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/30/2012	Year/Period of Report End of 2010/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				968		968	1
29,735				1,292,156		1,292,156	2
800				29,600		29,600	3
45,575				1,528,027		1,528,027	4
1,452				44,134		44,134	5
623,266				19,090,040		19,090,040	6
145,885				5,552,288		5,552,288	7
13,393				461,851		461,851	8
105,271				1,556,295		1,556,295	9
1,505,389				55,510,331		55,510,331	10
92,138				2,928,491		2,928,491	11
606,211				8,876,881		8,876,881	12
9,841				179,846		179,846	13
	59,000	77,103					14
13,556,311	516,115	533,248	19,732,200	430,075,448	120,850,035	570,657,683	

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,858				276,180		276,180	1
42,400				1,572,620		1,572,620	2
6,048				208,569		208,569	3
35,413				871,995		871,995	4
86,765				5,910,770		5,910,770	5
583,067				7,327,230		7,327,230	6
103,259				2,759,954		2,759,954	7
15,257				302,941		302,941	8
8,034				249,901		249,901	9
5,400				159,150		159,150	10
400				14,804		14,804	11
76,751				4,300,277		4,300,277	12
			1,030,200			1,030,200	13
1,216							14
13,556,311	516,115	533,248	19,732,200	430,075,448	120,850,035	570,657,683	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

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

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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)	
224,316				2,324,179		2,324,179	1
	26,100	26,070					2
1,457				44,236		44,236	3
	230						4
361,428							5
765,999				22,977,299		22,977,299	6
262,367				8,681,041		8,681,041	7
366,686				12,837,585		12,837,585	8
202,707				9,680,845		9,680,845	9
13,736				433,456		433,456	10
1,800				53,200		53,200	11
18,025				469,695		469,695	12
16,249				511,994		511,994	13
2,114				67,805		67,805	14
13,556,311	516,115	533,248	19,732,200	430,075,448	120,850,035	570,657,683	

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)	
116,456				3,782,969		3,782,969	1
11,400				419,762		419,762	2
1,597				47,224		47,224	3
2,810,811				94,230,809		94,230,809	4
219,000				9,417,000		9,417,000	5
4,733				166,374		166,374	6
128				2,045		2,045	7
478				13,286		13,286	8
-43,878				176,375		176,375	9
2,500				39,670		39,670	10
4				71		71	11
362,437				9,690,731		9,690,731	12
11,216				1,110,639		1,110,639	13
78,825				2,641,163		2,641,163	14
13,556,311	516,115	533,248	19,732,200	430,075,448	120,850,035	570,657,683	

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)	
1,517				88,173		88,173	1
100,387				4,361,964		4,361,964	2
414				30,411		30,411	3
46,113				1,803,033		1,803,033	4
41,015				1,350,132		1,350,132	5
3,200				142,400		142,400	6
205				8,720		8,720	7
68,889				2,208,160		2,208,160	8
19,902				757,524		757,524	9
1,714				56,522		56,522	10
28				580		580	11
22,345				747,663		747,663	12
2,579				83,262		83,262	13
65,261				2,027,057		2,027,057	14
13,556,311	516,115	533,248	19,732,200	430,075,448	120,850,035	570,657,683	

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)	
50,203				1,365,573		1,365,573	1
264,858				8,650,184		8,650,184	2
2,376				72,430		72,430	3
1,568				43,705		43,705	4
26,210				541,470		541,470	5
13,239				396,766		396,766	6
			18,702,000			18,702,000	7
	430,785	430,075					8
30,904				995,416		995,416	9
50,779				1,290,455		1,290,455	10
1,325,164				47,840,267		47,840,267	11
846,944				33,064,058		33,064,058	12
13,321				371,487		371,487	13
10,033				309,836		309,836	14
13,556,311	516,115	533,248	19,732,200	430,075,448	120,850,035	570,657,683	

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)	
568,317				20,175,345		20,175,345	1
8,817				253,808		253,808	2
368				24,562		24,562	3
126				9,133		9,133	4
107				6,831		6,831	5
296				19,559		19,559	6
343				21,121		21,121	7
1,966				123,031		123,031	8
24				1,250		1,250	9
138				8,808		8,808	10
226					9,953	9,953	11
					46,437	46,437	12
					113,637,597	113,637,597	13
							14
13,556,311	516,115	533,248	19,732,200	430,075,448	120,850,035	570,657,683	

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)	
					44,896	44,896	1
					7,385,960	7,385,960	2
							3
					-274,808	-274,808	4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
13,556,311	516,115	533,248	19,732,200	430,075,448	120,850,035	570,657,683	

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

The Chelan County contract expires on 10/31/11.

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 (39,993)

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

The Douglas County contract expires on 8/31/18.

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

Non jurisdictional utilities.

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

The ESI Vansycle Partners, LP contract expires 11/06/28.

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

The Eugene Water and Electric Board Memorandum of Understanding expires 12/31/13.

Schedule Page: 326.1 Line No.: 14 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: 326.2 Line No.: 1 Column: c

Non jurisdictional utilities.

Schedule Page: 326.2 Line No.: 5 Column: c

Non jurisdictional utilities.

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

The Iberdrola Renewables Wind contract expires on 11/30/35.

Schedule Page: 326.2 Line No.: 13 Column: a

Represents the value of energy delivered to the PGE control area from Electricity Service Suppliers in excess of the ESS's actual load within the PGE control area.

Schedule Page: 326.3 Line No.: 5 Column: b

The Morgan Stanley contract expires on 9/30/11.

Schedule Page: 326.4 Line No.: 1 Column: b

The PaTu Wind contract expires on 5/31/31.

Schedule Page: 326.5 Line No.: 5 Column: c

Non jurisdictional utilities.

Schedule Page: 326.5 Line No.: 7 Column: b

The Spokane Energy, LLC contract expires on 12/31/16.

Schedule Page: 326.5 Line No.: 12 Column: b

The TransAlta Energy Marketing contract expires on 9/30/16.

Name of Respondent Portland General Electric Company	This Report is: (1) __ An Original (2) X A Resubmission	Date of Report (Mo, Da, Yr) 05/30/2012	Year/Period of Report 2010/Q4

FOOTNOTE DATA

Schedule Page: 326.6 Line No.: 1 Column: b

The Warm Springs Contract expires on 2/29/12.

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: b

Power purchased from customers who operate generation facilities with less than 100 KW capacity.

Schedule Page: 326.6 Line No.: 8 Column: b

Power purchased from customers who operate generation facilities with less than 100 KW capacity.

Schedule Page: 326.6 Line No.: 9 Column: b

Power purchased from customers who operate generation facilities with less than 100 KW capacity.

Schedule Page: 326.6 Line No.: 10 Column: b

Power purchased from customers who operate generation facilities with less than 100 KW capacity.

Schedule Page: 326.6 Line No.: 11 Column: l

In accordance with Tariff Schedule 203, any excess credits accumulated by PGE Net Metering Service customers will be transferred to Low Income Assistance Program. Net metering measures the difference between the electricity supplied by PGE and that generated by the customer.

Schedule Page: 326.6 Line No.: 12 Column: l

Power purchased under Load Curtailment Program.

Schedule Page: 326.6 Line No.: 13 Column: l

Margin on electric financial transactions.

Schedule Page: 326.7 Line No.: 1 Column: l

Reserve for trading credit risk.

Schedule Page: 326.7 Line No.: 2 Column: l

Consists of expenses related primarily to the development of future renewable generation. Such expenses are fully offset by customer revenues.

Name of Respondent Portland General Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/30/2012	Year/Period of Report End of 2010/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	Avista Corp-Washington Water Power	Bonneville Power Administration	Various Utilities	NF
3	Barclay's Bank PLC	Bonneville Power Administration	Various Utilities	NF
4	Bonneville Power Administration	Bonneville Power Administration	Western Oregon Electric Coop	OLF
5	Bonneville Power Administration	Bonneville Power Administration	Western Oregon Electric Coop	OLF
6	Bonneville Power Administration	Bonneville Power Administration	Western Oregon Electric Coop	OS
7	Bonneville Power Administration	Bonneville Power Administration	Canby Public Utility	OLF
8	Bonneville Power Administration	Bonneville Power Administration	Columbia River PUD	FNO
9	Bonneville Power Administration	Bonneville Power Administration	Columbia River PUD	OLF
10	Bonneville Power Administration	Bonneville Power Administration	Portland General Electric	AD
11	Capital Power Corporation	Bonneville Power Administration	Various Utilities	AD
12	Capital Power Corporation	Bonneville Power Administration	Various Utilities	LFP
13	Cargill Power Markets, LLC	Bonneville Power Administration	Various Utilities	NF
14	Cargill Power Markets, LLC	Bonneville Power Administration	Various Utilities	SFP
15	Cargill Power Markets, LLC	Bonneville Power Administration	Various Utilities	AD
16	Constellation Energy Commodities	Bonneville Power Administration	Portland General Electric	NF
17	Constellation Energy Commodities	Bonneville Power Administration	Portland General Electric	AD
18	Constellation New Energy	Bonneville Power Administration	Various Utilities	NF
19	Constellation New Energy	Bonneville Power Administration	Various Utilities	NF
20	Constellation New Energy	Bonneville Power Administration	Portland General Electric	AD
21	Shell Energy North America	Bonneville Power Administration	Various Utilities	NF
22	Shell Energy North America	Bonneville Power Administration	Various Utilities	LFP
23	Shell Energy North America	Bonneville Power Administration	Various Utilities	SFP
24	Shell Energy North America	Bonneville Power Administration	Various Utilities	OS
25	Shell Energy North America	Bonneville Power Administration	Portland General Electric	AD
26	EPCOR Merchant and Capital US	Bonneville Power Administration	Portland General Electric	OLF
27	EPCOR Merchant and Capital US	Bonneville Power Administration	Portland General Electric	AD
28	Iberdrola Renewables Inc.	Bonneville Power Administration	Portland General Electric	NF
29	Macquarie Cook Power Inc.	Bonneville Power Administration	Portland General Electric	NF
30	Macquarie Cook Power Inc.	Bonneville Power Administration	Portland General Electric	NF
31	Macquarie Cook Power Inc.	Bonneville Power Administration	Portland General Electric	AD
32	Morgan Stanley Capital Group	Bonneville Power Administration	Various Utilities	NF
33	Morgan Stanley Capital Group	Bonneville Power Administration	Various Utilities	AD
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	Morgan Stanley Capital Group	Bonneville Power Administration	Various Utilities	SFP
2	PacifiCorp	PacifiCorp	Bonneville Power Administration	OS
3	PacifiCorp	PacifiCorp	Bonneville Power Administration	OS
4	PacifiCorp	Bonneville Power Administration	Bonneville Power Administration	AD
5	PacifiCorp	PacifiCorp	Various Utilities	NF
6	PacifiCorp	PacifiCorp	Bonneville Power Administration	OLF
7	Powerex	Bonneville Power Administration	Various Utilities	LFP
8	Powerex	Bonneville Power Administration	Various Utilities	SFP
9	Powerex	Bonneville Power Administration	Various Utilities	NF
10	Powerex	Bonneville Power Administration	Various Utilities	AD
11	Powerex	Bonneville Power Administration	Various Utilities	OS
12	Puget Sound Energy	Bonneville Power Administration	Various Utilities	NF
13	Puget Sound Energy	Bonneville Power Administration	Various Utilities	AD
14	Puget Sound Energy	Bonneville Power Administration	Various Utilities	NF
15	Sacramento Municipal UD	Bonneville Power Administration	Various Utilities	NF
16	Sacramento Municipal UD	Bonneville Power Administration	Various Utilities	AD
17	San Diego Gas and Electric	Bonneville Power Administration	Various Utilities	OLF
18	San Diego Gas and Electric	Bonneville Power Administration	Various Utilities	AD
19	Seattle City Light	Bonneville Power Administration	Various Utilities	NF
20	Sempra Energy Solutions	Bonneville Power Administration	Portland General Electric	NF
21	Sempra Energy Solutions	Bonneville Power Administration	Portland General Electric	AD
22	Sempra Energy Trading Co.	Bonneville Power Administration	Various Utilities	NF
23	Sempra Energy Trading Co.	Bonneville Power Administration	Various Utilities	AD
24	Snohomish County PUD	Bonneville Power Administration	Various Utilities	NF
25	Snohomish County PUD	Bonneville Power Administration	Various Utilities	AD
26	Tacoma Power	Bonneville Power Administration	Various Utilities	NF
27	The Energy Authority	Bonneville Power Administration	Various Utilities	NF
28	The Energy Authority	Bonneville Power Administration	Various Utilities	AD
29	TransAlta Energy Marketing US	Bonneville Power Administration	Various Utilities	NF
30	TransAlta Energy Marketing US	Bonneville Power Administration	Various Utilities	SFP
31	TransAlta Energy Marketing US	Bonneville Power Administration	Various Utilities	AD
32	TransAlta Energy Marketing US	Bonneville Power Administration	Various Utilities	OS
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	1,263,493	1,263,493	1
OA96137	BPA-John Day Sub	PGE-Malin Sub		8	8	2
OA96137	BPA-John Day Sub	PGE-Malin Sub		2,145	2,145	3
72	Various PGE Subs	Various PGE Subs		2,878	2,861	4
72	Various PGE Subs	Various PGE Subs		108,707	111,452	5
72	BPA Oregon City Subs	PGE-Canby				6
OA96137	BPA Oregon City Subs	PGE-Canby		144,311	144,428	7
OA96137	BPA-St. Johns Tap	PGE-St. Helens/Scap	12	121,672	117,446	8
OA96137	BPA-St. Johns Tap	PGE-St. Helens/Scap		482,137	481,334	9
OA96137	BPA-St. Johns Tap	PGE-St. Helens/Scap				10
OA96137	Various PGE Subs	Various PGE Subs				11
OA96137	Various PGE Subs	Various PGE Subs		71,914	71,105	12
OA96137	BPA-John Day Sub	PGE-Malin Sub		13,880	13,880	13
OA96137	BPA-John Day Sub	PGE-Malin Sub		43,864	43,864	14
OA96137	BPA-John Day Sub	PGE-Malin Sub				15
OA96137	BPA-John Day Sub	PGE-Malin Sub		6,346	6,346	16
OA96137	Various PGE Subs	Various PGE Subs				17
OA96137	BPA-John Day Sub	Various PGE Subs		40,336	26,732	18
OA96137	BPA-John Day Sub	Various PGE Subs		15,998	10,169	19
OA96137	Various PGE Subs	Various PGE Subs				20
OA96137	BPA-John Day Sub	PGE-Malin Sub		3,960	3,960	21
OA96137	BPA-John Day Sub	PGE-Malin Sub		1,708,511	1,708,511	22
OA96137	BPA-John Day Sub	BPA-John Day Sub	200	320	320	23
OA96137	BPA-John Day Sub	PGE-Malin Sub		2,579	2,579	24
OA96137	BPA-John Day Sub	Various PGE Subs				25
OA96137	Various PGE Subs	Various PGE Subs		55,219	53,624	26
OA96137	Various PGE Subs	Various PGE Subs				27
OA96137	Various PGE Subs	Various PGE Subs		31	31	28
OA96137	Various PGE Subs	Various PGE Subs				29
OA96137	Various PGE Subs	Various PGE Subs		15,154	15,154	30
OA96137	Various PGE Subs	Various PGE Subs				31
OA96137	BPA-John Day Sub	PGE-Malin Sub		16,576	16,576	32
OA96137	BPA-John Day Sub	PGE-Malin Sub				33
						34
			490	**7,253,886**	**7,296,338**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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)	MegaWatt Hours Delivered (j)	Line No.
OA96137	BPA-John Day Sub	PGE-Malin Sub		1,656	1,656	1
109	BPA-Bethel	PacifiCorp-Linneman		3,146	3,146	2
109	BPA-Bethel	PacifiCorp-Linneman		1,092	1,092	3
109	BPA-Bethel	PacifiCorp-Linneman				4
109	BPA-Bethel	PacifiCorp-Linneman		2,572	2,572	5
109	BPA-Bethel	PacifiCorp-Linneman		528	337	6
OA96137	BPA-John Day Sub	PGE-Malin Sub	165	1,089,243	1,089,243	7
OA96137	BPA-John Day Sub	PGE-Malin Sub		36,796	36,796	8
OA96137	BPA-John Day Sub	PGE-Malin Sub		37,591	37,591	9
OA96137	BPA-John Day Sub	PGE-Malin Sub				10
OA96137	BPA-John Day Sub	PGE-Malin Sub		2,204	2,204	11
OA96137	BPA-John Day Sub	PGE-Malin Sub		9,413	9,413	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		420	420	15
OA96137	BPA-John Day Sub	PGE-Malin Sub				16
OA96137	BPA-John Day Sub	PGE-Malin Sub	13	88,341	88,341	17
OA96137	BPA-John Day Sub	PGE-Malin Sub		4	4	18
OA96137	BPA-John Day Sub	PGE-Malin Sub		240,912	255,516	19
OA96137	Various PGE Subs	Various PGE Subs		1,406,497	1,458,557	20
OA96137	Various PGE Subs	Various PGE Subs		5,053	5,053	21
OA96137	Various PGE Subs	PGE-Malin Sub		2,060	2,060	22
OA96137	BPA-John Day Sub	PGE-Malin Sub		7,113	7,113	23
OA96137	BPA-John Day Sub	PGE-Malin Sub		4,390	4,390	24
OA96137	BPA-John Day Sub	PGE-Malin Sub				25
OA96137	BPA-John Day Sub	PGE-Malin Sub		732	732	26
OA96137	BPA-John Day Sub	PGE-Malin Sub				27
OA96137	BPA-John Day Sub	PGE-Malin Sub				28
OA96137	BPA-John Day Sub	PGE-Malin Sub		176,516	176,516	29
OA96137	BPA-John Day Sub	PGE-Malin Sub		17,540	17,540	30
OA96137	BPA-John Day Sub	PGE-Malin Sub				31
OA96137	BPA-John Day Sub	PGE-Malin Sub		28	28	32
						33
						34
			490	**7,253,886**	**7,296,338**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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.
642,988			642,988	1
	106		106	2
	1,289		1,289	3
29,817			29,817	4
	142,903		142,903	5
11,772			11,772	6
162,213			162,213	7
57,020			57,020	8
107,911			107,911	9
		-561	-561	10
		-195	-195	11
14,292			14,292	12
	9,512		9,512	13
28,319			28,319	14
		-9,061	-9,061	15
	3,676		3,676	16
		-13,490	-13,490	17
11,669			11,669	18
	11,229		11,229	19
		-121	-121	20
	2,608		2,608	21
1,285,979			1,285,979	22
				23
				24
		-228	-228	25
	43,184		43,184	26
		-1,189	-1,189	27
	62		62	28
	15		15	29
	10,235		10,235	30
		-202	-202	31
	13,663		13,663	32
		2,653	2,653	33
				34
4,887,345	**725,153**	**104,514**	**5,717,012**	

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.
1,741			1,741	1
		61,806	61,806	2
	82,384		82,384	3
		20,619	20,619	4
	2,296		2,296	5
		61,806	61,806	6
1,060,932			1,060,932	7
28,271	381		28,652	8
	44,856		44,856	9
		2,577	2,577	10
				11
	9,521		9,521	12
		-1,896	-1,896	13
85,956			85,956	14
				15
		268	268	16
650,000			650,000	17
	4	-58	-54	18
238,490	1,294		239,784	19
459,761	223,398	4,500	687,659	20
	5,998	382	6,380	21
	2,391	-31,690	-29,299	22
		-734	-734	23
	3,751		3,751	24
		-1,000	-1,000	25
	423		423	26
	127		127	27
		-63	-63	28
	109,847	10,134	119,981	29
10,214			10,214	30
		257	257	31
				32
				33
				34
4,887,345	**725,153**	**104,514**	**5,717,012**	

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

Contract with Avista Corporation - Washington Water Power expires 01/01/2013.

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

Contract with Bonneville Power Administration continues until terminated.

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

Contract with Bonneville Power Administration continues until terminated.

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

Represents monthly facility usage charges.

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

Contract with Bonneville Power Administration continues until terminated.

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

Contract with Bonneville Power Administration continues until terminated.

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

Contract with Bonneville Power Administration continues until terminated.

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

Represents true-up for 2009 services

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

Represents true-up for 2009 services

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

Contract with Capital Power Corporation continues until terminated.

Schedule Page: 328 Line No.: 14 Column: d

Short-term firm point-to-point contracts are secured daily via reservations. Cargill Power Markets SFP totals:

	Billing Demand (MW)	Demand Charges
August	708	$14,159
September	708	14,160
Total		$28,319

Schedule Page: 328 Line No.: 15 Column: d

Represents true-up for 2009 services

Schedule Page: 328 Line No.: 17 Column: d

Represents true-up for 2009 services

Schedule Page: 328 Line No.: 20 Column: d

Represents true-up for 2009 services

Schedule Page: 328 Line No.: 22 Column: d

Represents true-up for 2009 services

Schedule Page: 328 Line No.: 23 Column: d

Represents true-up for 2009 services

Schedule Page: 328 Line No.: 24 Column: d

Represents non-billed redirected MWHs of Shell Energy North America's LFP reservations.

Schedule Page: 328 Line No.: 25 Column: d

Represents true-up for 2009 services

Schedule Page: 328 Line No.: 27 Column: d

Represents true-up for 2009 services.

Schedule Page: 328 Line No.: 31 Column: d

Represents true-up for 2009 services

Schedule Page: 328 Line No.: 33 Column: d

Represents true-up for 2009 services

Schedule Page: 328.1 Line No.: 1 Column: d

Short-term firm point-to-point contracts are secured daily via reservations. Morgan Capital Group's SFP totals:

	Billing Demand (MW)	Demand Charges
August	50	$ 871
September	50	870
Total		$ 1,741

Schedule Page: 328.1 Line No.: 2 Column: d

Represents monthly facility usage charges.

Schedule Page: 328.1 Line No.: 3 Column: d

Represents monthly facility usage charges.

Schedule Page: 328.1 Line No.: 4 Column: d

Represents true-up for 2009 services

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

Contract with PacifiCorp continues until terminated

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

Contract with Powerex expires 06/01/2013

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

Short-term firm point-to-point contracts are secured daily via reservations. Powerex SFP totals:

	Billing Demand (MW)	Demand Charges
June	732	$ 14,441
July	686	13,830
		$ 28,271

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

Represents true-up for 2009 services

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

Represents non-billed redirected MWHs of Powerex's reservations

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

Represents true-up for 2009 services

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

Represents true-up for 2009 services

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

Contract with San Diego Gas & Electric expires 12/31/2013.

Schedule Page: 328.1 Line No.: 18 Column: d

Represents true-up for 2009 services

Schedule Page: 328.1 Line No.: 21 Column: d

Represents true-up for 2009 services

Schedule Page: 328.1 Line No.: 23 Column: d

Represents true-up for 2009 services

Schedule Page: 328.1 Line No.: 25 Column: d

Represents true-up for 2009 services

Schedule Page: 328.1 Line No.: 28 Column: d

Represents true-up for 2009 services

Schedule Page: 328.1 Line No.: 30 Column: d

Short-term firm point-to-point contracts are secured daily via reservations. Trans Alta Energy Marketing’s SFP totals:

	Billing Demand (MW)	Demand Charges
July	536	$10,214

Schedule Page: 328.1 Line No.: 31 Column: d

Represents true-up for 2009 services

Schedule Page: 328.1 Line No.: 32 Column: d

Represents non-billed redirected MWHs of Trans Alta's reservations.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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					
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34					
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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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

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

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp	NF	14,119	14,119		57,881		57,881
2	Bonneville Power Admin	LFP			49,800,405			49,800,405
3	Bonneville Power Admin	OS					15,641,500	15,641,500
4	Bonneville Power Admin	NF	76,557	76,557		437,071		437,071
5	BPA Amortization	FNS					196,416	196,416
6	Columbia River PUD	NF	11	11		4,136		4,136
7	Fale-Safe, Inc	OS					535,076	535,076
8	Idaho Power Company	NF	875	875		-1,495		-1,495
9	Los Angeles Dept.	NF	201	201		1,809		1,809
10	McMinnville Water & Lig	NF	973	973		4,670		4,670
11	Montana, State of	OS					844,078	844,078
12	Northwestern Corp	NF	76,294	76,294		348,526		348,526
13	NorthWest Power Pool	OS					14,695	14,695
14	PacifiCorp	OS					95,106	95,106
15	PacifiCorp	NF	1,241,730	1,241,730		1,065,301		1,065,301
16	Powerex	NF	2,836	2,836		4,122		4,122
	TOTAL		1,428,019	1,428,019	49,800,405	1,947,692	17,326,871	69,074,968

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	Puget Sound Energy	NF	14,423	14,423		25,671		25,671
2	Salem Electric	OS						
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		1,428,019	1,428,019	49,800,405	1,947,692	17,326,871	69,074,968

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

The Bonneville Power Administration PTP Network contract expires on 12/31/14. The PTP contract for Slatt expires on 12/31/2013, the PTP contract for Rocky Reach expires on 5/31/2015, the PTP contract for John Day and Big Eddy expires on 9/30/2015, and the PTP contract for Vansycle expires on 11/30/2016.

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

Represents Bonneville Power Administration Ancillary Transmission Services.

Schedule Page: 332 Line No.: 5 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.: 7 Column: g

Represents payment for certain Fale-Safe obligations, net of interest income, in exchange for additional access to Intertie.

Schedule Page: 332 Line No.: 11 Column: g

Represents Beneficial Use Tax and Wholesale Energy Transaction Tax payments to the State of Montana for use of BPA's transmission lines.

Schedule Page: 332 Line No.: 13 Column: g

Represents Ancillary Services under the Pacific Northwest Coordinating Agreement.

Schedule Page: 332 Line No.: 14 Column: g

Represents PacifiCorp's Linneman Transmission Services.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,963,242
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	198,100
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,159,944
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Involuntary Severence	2,119,582
7	Directors Pension	49,923
8	Directors Fees & Expenses	871,134
9	Misc Admin R&D Expenses	3,234
10		
11		
12		
13		
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43		
44		
45		
46	TOTAL	6,365,159

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			17,223,182		17,223,182
2	Steam Production Plant	12,205,076	208,751			12,413,827
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	6,550,482	64			6,550,546
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	51,922,012	49,878			51,971,890
7	Transmission Plant	10,469,714	1,676			10,471,390
8	Distribution Plant	112,457,083	9,615			112,466,698
9	Regional Transmission and Market Operation					
10	General Plant	15,347,715	2,079			15,349,794
11	Common Plant-Electric					
12	TOTAL	208,952,082	272,063	17,223,182		226,447,327

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, forty-year, and fifty-year amortization of hydro licensing costs.

On December 21, 2010, the FERC issued a forty-year license for PGE's hydro projects on the Clackamas River. On March 17, 2011, the FERC issued an Order on Rehearing that increased the license period to forty-five years.

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Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Note: Complete data						
13	will be provided in						
14	the 2011 Form 1						
15	(5 year interval)						
16							
17							
18							
19							
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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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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-2006 Audit		246,786	246,786	
2	Docket No. PA06-9				
3					
4	FERC-California Refund		56,151	56,151	
5	Docket No. EL00-95				
6					
7	FERC-OATT Investigation		61,343	61,343	
8	Docket No. IN10-2				
9					
10	OPUC-2011 Rate Case		620,935	620,935	
11	Docket No. UE-215				
12					
13	OPUC-Integrated Resource Plan 2009		133,091	133,091	
14	Docket No. LC-48				
15					
16	OPUC-Investigation into Forecasting		43,294	43,294	
17	Forced Outage Rate				
18	Docket No. UM-1355				
19					
20	OPUC-SB 408 Implementation Tax Adjustment		41,909	41,909	
21	Docket No. AR-499				
22					
23	OPUC-Appeal of OPUC Order 08-487		148,802	148,802	
24	Docket No. A-14031				
25					
26	BPA-BPA Wholesale Power Rate Case		44,258	44,258	
27	Appeal- Non Rate				
28	Docket No. WPA-10				
29					
30	FERC matters less than $25,000		10,168	10,168	
31					
32	OPUC matters less than $25,000		152,810	152,810	
33					
34	Non Docs matters less than $25,000		249,298	249,298	
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL		1,808,845	1,808,845	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

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	246,786					1
							2
							3
	928	56,151					4
							5
							6
	928	61,343					7
							8
							9
	928	620,935					10
							11
							12
	928	133,091					13
							14
							15
	928	43,294					16
							17
							18
							19
	928	41,909					20
							21
							22
	928	148,802					23
							24
							25
	928	44,258					26
							27
							28
							29
	928	10,168					30
							31
	928	152,810					32
							33
	928	249,298					34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		1,808,845					46

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	A(6)	Electric R, D & D Performed Internally - Other
10		
11	B(1)	Electric R, D & D Performed Externally
12		Research Support to the Electrical Research Council or EPRI
13		
14		
15		
16		
17		
18		
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21		
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23		
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25		
26		
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28		
29	Totals	
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38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
134,000		930.2	134,000		3
					4
48,782		930.2	48,782		5
					6
10,000		930.2	10,000		7
					8
318		930.2	318		9
					10
					11
	5,000	930.2	5,000		12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
193,100	5,000		198,100		29
					30
					31
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					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	24,367,389		
4	Transmission	4,194,972		
5	Regional Market			
6	Distribution	15,673,482		
7	Customer Accounts	26,150,625		
8	Customer Service and Informational	4,966,520		
9	Sales			
10	Administrative and General	38,125,882		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	113,478,870		
12	Maintenance			
13	Production	9,205,588		
14	Transmission	1,142,323		
15	Regional Market			
16	Distribution	16,833,118		
17	Administrative and General	598,935		
18	TOTAL Maintenance (Total of lines 13 thru 17)	27,779,964		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	33,572,977		
21	Transmission (Enter Total of lines 4 and 14)	5,337,295		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	32,506,600		
24	Customer Accounts (Transcribe from line 7)	26,150,625		
25	Customer Service and Informational (Transcribe from line 8)	4,966,520		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	38,724,817		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	141,258,834	15,062,440	156,321,274
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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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)	141,258,834	15,062,440	156,321,274
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	54,966,904	5,151,827	60,118,731
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	54,966,904	5,151,827	60,118,731
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,054,448	-187	2,054,261
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,054,448	-187	2,054,261
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	2,221,794	165,227	2,387,021
79	Co-owner Shares of Generating Facilities	8,021,416	401,976	8,423,392
80	Other	4,122,953	135,319	4,258,272
81	Payroll Allocated	20,916,602	-20,916,602	
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	35,282,765	-20,214,080	15,068,685
96	TOTAL SALARIES AND WAGES	233,562,951		233,562,951

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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)	(49,529)	275,954	601,212	1,556,295
3	Net Sales (Account 447)	1,699,768	1,230,091	2,234,362	6,811,265
4	Transmission Rights				
5	Ancillary Services	44,945	31,204	32,671	134,487
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
14					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	1,695,184	1,537,249	2,868,245	8,502,047

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		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	44,759	MW	13,626,190	4,145,738	Various	93,804
2	Reactive Supply and Voltage		MW		1,537,954	Various	51,319
3	Regulation and Frequency Response				1,537,939	Various	119,396
4	Energy Imbalance	15,304	MW-Hour	1,207,314	39,863	MW-Hour	488,325
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	60,063		14,833,504	7,261,494		752,844

Schedule Page: 398 Line No.: 1 Column: g

Scheduling, System Control and Dispatch

No. of Units	Unit of Measure	Amount
73,966	MW Day	$ 2,217
149,610	MW Hour	2,999
30,246	MW Month	2,935
23,328	MW Week	576
2,330,784	MW Year	69,699
1,537,804	Sum of Peak Demand (KW)	15,378
4,145,738		$93,804

Schedule Page: 398 Line No.: 2 Column: b

None in 2010.

Schedule Page: 398 Line No.: 2 Column: d

None in 2010.

Schedule Page: 398 Line No.: 2 Column: g

Reactive Supply and Voltage

No. of Units	Unit of Measure	Amount
15	MW Hour	$ 1
135	MW Month	5,184
1,537,804	Sum of Peak Demand (KW)	46,134
1,537,954		$51,319

Schedule Page: 398 Line No.: 3 Column: g

Regulation and Frequency Response

No. of Units	Unit of Measure	Amount
135	MW Hour	$ 11,750
1,537,804	Sum of Peak Demand (KW)	107,646
1,537,939		$119,396

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.

FOOTNOTE DATA

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	3,840	6	1800	3,009	139	1,347	13	750	126
2	February	3,724	1	1900	2,898	136	1,347	13	3,150	63
3	March	3,619	12	1100	2,642	137	665	13	3,982	
4	Total for Quarter 1	11,183			8,549	412	3,359	39	7,882	189
5	April	3,424	5	2200	2,609	123	665	13	4,007	
6	May	3,276	28	1000	2,326	132	665	13	4,007	66
7	June	3,542	24	1800	2,616	143	665	13	3,857	
8	Total for Quarter 2	10,242			7,551	398	1,995	39	11,871	66
9	July	4,366	9	1700	3,282	156	665	13	3,870	200
10	August	4,430	25	1800	3,250	156	665	13	3,905	
11	September	3,763	3	1700	2,908	150	665	13	3,905	133
12	Total for Quarter 3	12,559			9,440	462	1,995	39	11,680	333
13	October	3,581	25	2000	2,629	132	665	13	4,007	
14	November	4,413	24	900	3,382	142	665	13	4,041	64
15	December	4,429	14	1800	3,059	141	665	13	4,107	83
16	Total for Quarter 4	12,423			9,070	415	1,995	39	12,155	147
17	Total Year to Date/Year	46,407			34,610	1,687	9,344	156	43,588	735

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2010/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	262	22	700			307			
2	February	274	11	2400			307			
3	March	280	25	700			307			
4	Total for Quarter 1	816					921			
5	April	279	20	400			307			
6	May	283	31	2300			307			
7	June	278	1	100			307			
8	Total for Quarter 2	840					921			
9	July	281	6	2300			307			
10	August	265	20	600			307			
11	September	269	15	400			307			
12	Total for Quarter 3	815					921			
13	October	278	9	2400			307			
14	November	279	6	2100			307			
15	December	278	15	2400			307			
16	Total for Quarter 4	835					921			
17	Total Year to Date/Year	3,306					3,684			

Schedule Page: 400 Line No.: 4 Column: g

Long Term Firm Point-to-Point Reservation:

Reservation #	Customer	January Capacity	February Capacity	March Capacity	Earliest Termination Date
432190	Portland General Electric Co	200	200	200	1/1/2012
71324505	Powerex	165	165	165	6/1/2013
71324658	Avista Corporation	100	100	100	1/1/2013
72905636	Portland General Electric Co	2	2		3/1/2010
72905627	Portland General Electric Co	480	480		3/1/2010
72905632	Portland General Electric Co	200	200		3/1/2010
315999	Avista Corporation	200	200	200	1/1/2022
	Total	1,347	1,347	665	

Schedule Page: 400 Line No.: 4 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.: 4 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
73709206	Portland General Electric Co	150		
73709209	Portland General Electric Co	600		
73822405	Portland General Electric Co		150	
73822411	Portland General Electric Co		3,000	
73900703	Portland General Electric Co			2
73900686	Portland General Electric Co			3,000
73840027	Portland General Electric Co			300
73900693	Portland General Electric Co			480
73900700	Portland General Electric Co			200
	Total	750	3,150	3,982

Schedule Page: 400 Line No.: 4 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 Line No.: 8 Column: g

Long Term Firm Point-to-Point Reservation:

Reservation #	Customer	April Capacity	May Capacity	June Capacity	Earliest Termination Date
432190	Portland General Electric Co	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
	Total	665	665	665	

Schedule Page: 400 Line No.: 8 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.: 8 Column: i

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
73900693	Portland General Electric Co	480	480	480
73900700	Portland General Electric Co	200	200	200
73900703	Portland General Electric Co	2	2	2
73990217	Portland General Electric Co	25	25	25
93840027	Portland General Electric Co	300	300	
73990228	Portland General Electric Co	3,000		
74107419	Portland General Electric Co		3,000	
74229140	Portland General Electric Co			3,000
74229147	Portland General Electric Co			150
	Total	4,007	4,007	3,857

Schedule Page: 400 Line No.: 8 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 Line No.: 12 Column: g

Long Term Firm Point-to-Point Reservation:

Reservation #	Customer	July Capacity	August Capacity	September Capacity	Earliest Termination Date
432190	Portland General Electric Co	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
	Total	665	665	665	

Schedule Page: 400 Line No.: 12 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.: 12 Column: i

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
73900693	Portland General Electric Co	480	480	480
73900700	Portland General Electric Co	200	200	200
73900703	Portland General Electric Co	2	2	2
73990217	Portland General Electric Co	25	25	25

74388473	Portland General Electric Co	3,000		
74520057	Portland General Electric Co		3,000	
74622005	Portland General Electric Co			3,000
74388478	Portland General Electric Co	150		
74514869	Portland General Electric Co		150	
74622001	Portland General Electric Co			150
74438474	Transalta Energy Marketing US Inc.	13		
74610095	Cargill Power Markets, LLC		48	
74638034	Cargill Power Markets, LLC			48
	Total	3,870	3,905	3,905

Schedule Page: 400 Line No.: 12 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 Line No.: 16 Column: g

Long Term Firm Point-to-Point Reservation:

Reservation #	Customer	October Capacity	November Capacity	December Capacity	Earliest Termination Date
432190	Portland General Electric Co	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
	Total	665	665	665	

Schedule Page: 400 Line No.: 16 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.: 16 Column: i

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
74687802	Portland General Electric Co	300	300	300
73900703	Portland General Electric Co	2	2	2
73990217	Portland General Electric Co	25	25	25
73900693	Portland General Electric Co	480	480	480
73900700	Portland General Electric Co	200	200	200
74721670	Portland General Electric Co	3,000		
74813594	Portland General Electric Co		3,000	
74914370	Portland General Electric Co		34	
74915478	Portland General Electric Co			3,000
74850035	Portland General Electric Co			100
	Total	4,007	4,041	4,107

Schedule Page: 400 Line No.: 16 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.: 4 Column: b

Monthly Peak MW:
The entries represent the "Transmission Providers 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 facilities transmission system during the calendar month.

Schedule Page: 400.1 Line No.: 4 Column: g

Long-Term Firm Point-to-Point Reservation:

Reservation #	Customer	Capacity	Earliest Termination Date
73065442	Portland General Electric Co	27	7/1/2022
73068563	Portland General Electric Co	280	7/1/2022
	Total	307	

Schedule Page: 400.1 Line No.: 8 Column: b

Monthly Peak MW:
The entries represent the "Transmission Providers 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 facilities transmission system during the calendar month

Schedule Page: 400.1 Line No.: 8 Column: g

Long-Term Firm Point-to-Point Reservation:

Reservation #	Customer	Capacity	Earliest Termination Date
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	Total	307	

Schedule Page: 400.1 Line No.: 12 Column: b

Monthly Peak MW:
The entries represent the "Transmission Providers 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 facilities transmission system during the calendar month.

Schedule Page: 400.1 Line No.: 12 Column: g

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Monthly Peak MW:
The entries represent the "Transmission Providers 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 facilities transmission system during the calendar month.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) __ An Original (2) X A Resubmission	05/30/2012	2010/Q4

FOOTNOTE DATA

Schedule Page: 400.1 Line No.: 16 Column: g

Long-Term Firm Point-to-Point Reservation:

Reservation #	Customer	Capacity	Earliest Termination Date
73065442	Portland General Electric Co	27	7/1/2022
73068563	Portland General Electric Co	280	7/1/2022
	Total	307	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	17,683,065
3	Steam	4,984,503			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	1,829,898			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,803,712
7	Other	5,292,913			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	12,107,314	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	23,610
10	Purchases	13,556,311	27	Total Energy Losses	1,093,653
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	25,604,040
12	Received	516,115			
13	Delivered	533,248			
14	Net Exchanges (Line 12 minus line 13)	-17,133			
15	Transmission For Other (Wheeling)				
16	Received	7,253,886			
17	Delivered	7,296,338			
18	Net Transmission for Other (Line 16 minus line 17)	-42,452			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	25,604,040			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	2,283,203	574,756	3,187	7	1800
30	February	2,111,211	622,762	3,029	10	1900
31	March	2,216,636	615,642	2,992	9	1900
32	April	2,307,271	807,126	2,837	5	1100
33	May	1,803,060	341,616	2,635	6	800
34	June	2,074,902	660,932	2,699	24	1800
35	July	2,224,963	652,241	3,456	8	1700
36	August	2,259,616	691,270	3,544	16	1800
37	September	2,057,964	597,624	3,049	3	1700
38	October	1,990,991	472,887	2,775	26	1900
39	November	2,145,984	468,209	3,582	23	1900
40	December	2,170,691	347,670	3,361	31	1800
41	TOTAL	25,646,492	6,852,735			

Schedule Page: 401 Line No.: 7 Column: b

Includes 833,387 megawatt hours of net wind generation from PGE's Biglow Canyon Wind Project which was placed in service in three phases between December 2007 and August 2010. Key statistics related to the projects include the following:

In-service Production cost at 12/31/2010: $960,300,035
Total installed capacity: 450 megawatts
Operations and Maintenance expenses for 2010: $11,408,453

Schedule Page: 401 Line No.: 29 Column: c

Line 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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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)	584	0
7	Plant Hours Connected to Load	7538	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	111	0
12	Net Generation, Exclusive of Plant Use - KWh	4087303000	2651352000
13	Cost of Plant: Land and Land Rights	1240068	798843
14	Structures and Improvements	153062273	101044056
15	Equipment Costs	494483228	317788376
16	Asset Retirement Costs	6828195	5355811
17	Total Cost	655613764	424987086
18	Cost per KW of Installed Capacity (line 17/5) Including	1020.8872	1018.1038
19	Production Expenses: Oper, Supv, & Engr	7143046	4343234
20	Fuel	70282502	46512845
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	2489341	1601514
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	16705721	10520345
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	49277	25007
34	Total Production Expenses	96669887	63002945
35	Expenses per Net KWh	0.0237	0.0238

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels				
38	Quantity (Units) of Fuel Burned	2416798	5930	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	28.257	93.952	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	28.818	107.039	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.692	18.388	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.017	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10072.100	0.000	0.000	0.000	0.000	0.000

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Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	2333151000
13	Cost of Plant: Land and Land Rights	0	3327908
14	Structures and Improvements	0	114784205
15	Equipment Costs	0	313775002
16	Asset Retirement Costs	0	-285471
17	Total Cost	0	431601644
18	Cost per KW of Installed Capacity (line 17/5) Including	0	1386.8947
19	Production Expenses: Oper, Supv, & Engr	0	4556302
20	Fuel	0	26291511
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	36249
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	6111875
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	36995937
35	Expenses per Net KWh	0.0000	0.0159

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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
488			422			257			6
861			7315			7207			7
0			0			0			8
533			424			243			9
0			0			0			10
54			20			26			11
164579000			2740177000			1554770000			12
0			0			0			13
30021011			40526009			10758578			14
172739679			217035652			144599985			15
42315			226391			112544			16
202803005			257788052			155471107			17
332.0829			533.3914			583.6003			18
1357825			2726530			2019939			19
26786536			149777152			91113041			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
3170697			1342438			752901			26
180648			34012			67255			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
2966832			6436273			3934429			32
54335			6492			186			33
34516873			160322897			97887751			34
0.2097			0.0585			0.0630			35
Gas	Oil		Gas	Oil		Gas	Oil		36
Mcf's	Barrels		Mcf's	Barrels		Mcf's	Barrels		37
1641676	903	0	18915346	0	0	11820673	0	0	38
1011000	138600	0	1011000	138600	0	1011000	138600	0	39
3.974	98.579	0.000	4.629	0.000	0.000	4.072	0.000	0.000	40
16.213	188.023	0.000	7.918	0.000	0.000	7.708	0.000	0.000	41
16.035	32.340	0.000	7.831	0.000	0.000	7.623	0.000	0.000	42
0.162	0.001	0.000	0.055	0.000	0.000	0.059	0.000	0.000	43
10091.040	0.000	0.000	6979.700	0.000	0.000	7687.400	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 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			0			0			18
0			0			0			19
0			0			0			20
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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
									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.

Schedule Page: 402 Line No.: 38 Column: d1

Updated 5/30/12 to reflect storage gas (in addition to delivered gas) burned during 2010.

Schedule Page: 402 Line No.: 40 Column: d1

Updated 5/30/12 to reflect storage gas (in addition to delivered gas) burned during 2010.

Schedule Page: 402 Line No.: 41 Column: d1

Updated 5/30/12 to reflect storage gas (in addition to delivered gas) burned during 2010.

Schedule Page: 402 Line No.: 42 Column: d1

Updated 5/30/12 to reflect storage gas (in addition to delivered gas) burned during 2010.

Schedule Page: 402 Line No.: 44 Column: b2

The Boardman Coal Plant does not use oil for generation. Oil is used during startup or upset conditions and other temporary operational purposes.

Schedule Page: 402 Line No.: 44 Column: d1

Updated 5/30/12 to reflect storage gas (in addition to delivered gas) burned during 2010 and composite heatrate per instruction No. 8 of this page. The Beaver Plant uses gas extensively for generation with minimal oil useage. The Average BTU per KWh Net Generation reported is a composite heat rate for both fuels.

Schedule Page: 402 Line No.: 44 Column: d2

Updated 5/30/12 to reflect Gas as main fuel and reporting of a composite heatrate under gas column (per Instruction No. 8 of this page).

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Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	49
7	Plant Hours Connect to Load	0	8,754
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	44
12	Net Generation, Exclusive of Plant Use - Kwh	0	180,896,000
13	Cost of Plant		
14	Land and Land Rights	0	33,434
15	Structures and Improvements	0	3,448,770
16	Reservoirs, Dams, and Waterways	0	18,389,276
17	Equipment Costs	0	8,235,658
18	Roads, Railroads, and Bridges	0	1,956,781
19	Asset Retirement Costs	0	76
20	TOTAL cost (Total of 14 thru 19)	0	32,063,995
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	871.3042
22	Production Expenses		
23	Operation Supervision and Engineering	0	245,093
24	Water for Power	0	20,766
25	Hydraulic Expenses	0	43,329
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	698,160
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	2,097,603
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	42,490
34	Total Production Expenses (total 23 thru 33)	0	3,147,441
35	Expenses per net KWh	0.0000	0.0174

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating 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)	107	0
7	Plant Hours Connect to Load	6,942	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	424,332,000	282,902,000
13	Cost of Plant		
14	Land and Land Rights	3,672,025	2,448,139
15	Structures and Improvements	8,067,574	5,312,851
16	Reservoirs, Dams, and Waterways	14,288,599	9,691,144
17	Equipment Costs	8,468,772	5,647,261
18	Roads, Railroads, and Bridges	3,217,818	2,150,177
19	Asset Retirement Costs	0	42
20	TOTAL cost (Total of 14 thru 19)	37,714,788	25,249,614
21	Cost per KW of Installed Capacity (line 20 / 5)	343.4862	345.8851
22	Production Expenses		
23	Operation Supervision and Engineering	334,682	216,373
24	Water for Power	47,252	19,279
25	Hydraulic Expenses	838,377	272,632
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	418,234	272,049
28	Rents	12,529	12,868
29	Maintenance Supervision and Engineering	381,644	118,863
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	136,494	59,131
34	Total Production Expenses (total 23 thru 33)	2,169,212	971,195
35	Expenses per net KWh	0.0051	0.0034

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	26	44	6
8,749	8,756	8,750	7
			8
58	25	44	9
43	20	49	10
0	0	8	11
207,854,000	113,018,000	241,961,000	12
			13
377,100	86,408	9,457	14
3,758,247	2,753,594	4,495,801	15
19,945,883	37,179,666	19,366,404	16
8,036,442	5,376,538	8,105,705	17
1,650,264	458,019	2,161,949	18
5	54	1,769	19
33,767,941	45,854,279	34,141,085	20
827.6456	2,426.1523	669.4330	21
			22
231,319	224,009	307,335	23
23,195	13,829	26,970	24
251,555	80,643	247,670	25
0	0	0	26
133,885	112,545	243,112	27
85,659	0	-834,864	28
92,990	134,077	1,137,054	29
0	0	0	30
0	0	0	31
0	0	0	32
301,629	69,288	161,821	33
1,120,232	634,391	1,289,098	34
0.0054	0.0056	0.0053	35

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
306	0	19	6
7,068	0	8,742	7
			8
338	0	18	9
210	0	9	10
41	0	1	11
1,000,546,000	667,064,000	136,203,000	12
			13
3,726,481	2,521,011	572,077	14
10,531,891	7,039,317	9,305,362	15
159,066,931	103,292,003	19,793,994	16
20,685,558	13,784,636	12,529,751	17
1,336,451	896,127	0	18
0	106	2,224	19
195,347,312	127,533,200	42,203,408	20
790.8798	772.9285	2,740.4810	21
			22
334,885	238,087	158,609	23
105,342	82,456	31,191	24
2,247,815	1,784,932	61,880	25
0	0	0	26
470,531	350,926	143,911	27
-14,374	-14,097	0	28
1,192,703	977,700	192,318	29
0	0	0	30
0	0	0	31
0	0	0	32
161,320	98,023	46,638	33
4,498,222	3,518,027	634,547	34
0.0045	0.0053	0.0047	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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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.
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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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	5	104,631
2	Oregon Military Dept/A.F.R.C	2001	1.60	1.6	49	164,147
3	US Bank Corp Columbia Center	2001	6.40	6.2	356	488,059
4	Providence Business Center	2004	2.00	1.8	27	385,944
5	Portland State University	2004	2.80	2.8	47	261,732
6	Oregon Military Joint Forces HQ	2005	1.60	1.6	50	191,440
7	Stimson Lumber	2005	0.57	0.5	6	160,253
8	FORTIX (ViaWest)	2005	1.00	0.9	2	88,337
9	Skyline	2005	2.00	1.8	27	201,526
10	Tri-Quint	2005	0.60	0.5	7	109,968
11	NCCWC- Filter Plant	2005	2.00	1.8	32	122,958
12	PCC Structurals	2005	1.00	0.9	11	114,803
13	Providence Portland Medical Center	2005	6.00	5.4	317	257,579
14	Salem Hospital	2006	4.00	3.6	167	188,494
15	Sunrise Water Authority Pump Station	2006	1.25	1.1	16	88,886
16	Providence Newberg Hospital	2006	1.50	1.4	54	156,833
17	Sungard DSG	2006	2.00	1.8	28	331,845
18	Kaiser Sunnyside Hospital	2007	4.50	4.0	188	352,752
19	Newberg Waste Water Treatment Plant	2008	2.00	1.8	31	152,739
20	Xerox Corp	2007	4.00	3.6	119	380,259
21	Newberg Water Treatment Plant	2007	1.00	0.9	7	77,947
22	Solaicx	2008	1.00	0.9	9	62,963
23	Solar World	2008	3.00	2.7	89	219,916
24	Oregon Dept of Admin Serv - Data Center	2010	2.00	1.8	35	277,187
25	Sanyo	2010	1.00	0.9	6	43,056
26	Sysco Foods	2010	2.00	1.8		141,709
27	Total					5,125,963
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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) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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		1,558	5,329	diesel-low s	1,779	1
102,592		12,494	12,045	diesel-low s or gas	1,607	2
76,259		35,634	49,785	diesel-low s	1,614	3
192,972		5,598	6,043	diesel-low s	1,679	4
93,476		10,015	16,748	diesel-low s	1,721	5
119,650		3,179	13,944	diesel-low s	1,471	6
283,634		1,688	4,928	diesel-low s	1,743	7
88,337		730	43,493	diesel-low s	1,307	8
100,763		7,956	21,925	diesel-low s	1,614	9
183,279		1,548	3,657	diesel-low s	1,686	10
61,479		4,321	6,380	diesel-low s	1,729	11
114,803		2,806	3,832	diesel-low s	1,779	12
42,930		27,699	25,532	diesel-low s	1,664	13
47,124		26,254	19,554	diesel-low s	1,721	14
71,108		3,421	10,447	diesel-low s	1,707	15
104,555		6,713	10,356	diesel-low s	1,764	16
165,922		5,132	7,545	diesel-low s	1,857	17
78,389		7,259	16,120	diesel-low s	1,471	18
76,369		2,917	11,270	diesel-low s	1,679	19
95,065		10,848	9,884	diesel-low s	1,657	20
77,947		4,559	8,900	diesel-low s	1,771	21
62,963		2,288	5,439	diesel-low s	1,607	22
73,305		1,216	12,949	diesel-low s	1,836	23
138,594		2,903	18,156	diesel-low s	1,586	24
43,056			1,781	diesel-low s		25
70,854		12,177	1,868	diesel-low s	1,614	26
		200,913	347,910			27
						28
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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)	Structure (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	COYOTE SPRINGS	BPA SLATT	500.00	500.00	ST. TOWER	28.10		2
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	BIGLOW CANYON WF	JOHN DAY	230.00	230.00	ST. TOWER	6.82		1
16	PELTON 230KV PROJECT							
17	PELTON	ROUND BUTTE	230.00	230.00	H-WOOD	7.87		1
18								
19	NON PROJECT 230KV:							
20	BETHEL	ROUND BUTTE	230.00	230.00	H-WOOD	55.19		1
21			230.00	230.00	ST. TOWER	44.85		1
22	ROUND BUTTE	BPA REDMOND	230.00	230.00	H-WOOD	23.60		1
23	BETHEL	BPA TIE (SANTIAM)	230.00	230.00	H-WOOD	3.60		1
24	BETHEL	McLOUGHLIN	230.00	230.00	H-WOOD	35.70		1
25	CARVER	GRESHAM	230.00	230.00	H-WOOD	7.39		1
26	McLOUGHLIN	CARVER	230.00	230.00	H-WOOD	4.95		1
27	McLOUGHLIN	CARVER	230.00	230.00	ST. MONOP	4.88		1
28	BPA KEELER	ST. MARY'S W.	230.00	230.00	H-WOOD	2.89		1
29			230.00	230.00	ST. TOWER	3.78		2
30	BLUE LAKE	TROUTDALE BPA	230.00	230.00	H-WOOD	0.80		1
31			230.00	230.00	ST. MONOP	0.58		1
32	PEARL BPA	SHERWOOD	230.00	230.00	ST. TOWER		4.72	2
33			230.00	230.00	ST. TOWER	0.16		1
34	GRESHAM	LINNEMAN	230.00	230.00	ST. TOWER	0.26		1
35	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER	11.10		1
36					TOTAL	625.47	543.22	57

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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			230.00	230.00	H-TOWER	0.60		1
2	NON PROJECT 230KV							
3	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER		4.40	2
4	ST. MARY'S W.	MURRAYHILL	230.00	230.00	ST. TOWER	5.92		1
5	MURRAYHILL	SHERWOOD	230.00	230.00	ST. TOWER	5.68		2
6	PORT WESTWARD	TROJAN	230.00	230.00	ST. MONOP	18.80		1
7			230.00	230.00	ST. MONOP	9.39		1
8	TROJAN	ST. MARY'S W.	230.00	230.00	H-WOOD	0.10		1
9			230.00	230.00	ST. TOWER	3.86		2
10			230.00	230.00	ST. TOWER	4.80		1
11			230.00	230.00	ST. TOWER	33.20		2
12	TROJAN	RIVERGATE	230.00	230.00	ST. TOWER		32.20	2
13			230.00	230.00	ST. TOWER	2.90		2
14	Tot Nonproj 230kv Costs							
15	GRESHAM	TROUTDALE	230.00	230.00	ST. TOWER		7.00	1
16	BOARDMAN	PPL DALREED	230.00	230.00	H-WOOD	16.75		1
17	Tot 230KV LINE EXPENSES							
18								
19	PROJECT 115 KV LINES							
20	FARADAY	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		1
21	NORTH FORK	FARADAY	115.00	115.00	H-WOOD	2.79		1
22	OAK GROVE	FARADAY	115.00	115.00	DC LATTICE	18.68		2
23	OAK GROVE	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		2
24			115.00	115.00	DC LATTICE	18.68		2
25	Tot 115KV LINE EXPENSES							
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	625.47	543.22	57

Name of Respondent Portland General Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/30/2012	Year/Period of Report End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
1780MCMACSR	50,953	1,645,820	1,696,773					2
1780MCMACSR	275,427	15,581,385	15,856,812					3
	5,904		5,904					4
1480MCMACSR		4,620,708	4,620,708					5
1780MCMACSR		3,624,934	3,624,934					6
								7
								8
								9
								10
								11
	1,480,658	42,812,486	44,293,144					12
				1,171,683	2,264,001	937,556	4,373,240	13
								14
1.6 IN. AACTW		3,040,852	3,040,852					15
								16
795MCMACSR	7,579	272,457	280,036					17
								18
								19
1272MCMACSR								20
1272MCMACSR								21
795MCMACSR								22
795MCMACSR								23
1272MCMACSR								24
1272MCMAAC								25
1272MCMAAC								26
1272MCMACSS								27
1590MCMACSRTW								28
1590MCMACSRTW								29
1780MCMACSR								30
								31
2388MCMAACTW								32
2388MCMAACTW								33
1272MCMAAC								34
1272MCMAAC								35
	10,450,319	136,692,357	147,142,676	1,440,307	2,783,053	1,030,813	5,254,173	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1780MCMACSR								1
								2
1272MCMAAC								3
1272MCMAAC								4
1272MCMAAC								5
2156MCMACSS								6
2156MCMACSS								7
1272MCMAAC								8
1272MCMAAC								9
1590MCMAAC								10
1590MCMAAC								11
1590MCMAAC								12
1272MCMACSR								13
	8,474,778	61,826,234	70,301,012					14
954KCMACSR								15
795KCMAAC		973,248	973,248					16
				268,624	519,052	5,000	792,676	17
								18
								19
795KCMACSR		502,020	502,020					20
556KCMACSR	120,248	621,351	741,599					21
250CU	12,477	420,125	432,602					22
795KCMACSR								23
250CU	22,295	750,737	773,032					24
						88,257	88,257	25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	10,450,319	136,692,357	147,142,676	1,440,307	2,783,053	1,030,813	5,254,173	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.: 6 Column: a

Contribution in Aid of Construction made in 1995 to Bonneville Power Administration not previously reported.

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.: 15 Column: a

Contribution in Aid of Construction made in 2007 to Bonneville Power Administration, not previously reported.

Schedule Page: 422 Line No.: 17 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.: 32 Column: a

Represents ownership of one circuit on Bonneville Power Administration's double circuit line.

Schedule Page: 422.1 Line No.: 15 Column: a

Represents contract with PacifiCorp whereby PGE is entitled to 1/2 the capacity of the line.

Schedule Page: 422.1 Line No.: 16 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) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2010/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	No Activity in 2010						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
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32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
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									14
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									42
									43
									44

Schedule Page: 424 Line No.: 1 Column: a

For Year 2010: No additions, retirements or significant revisions on PGE's transmission lines.

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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	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	Mobile sub No. 1, OR	Distrib./unattended	115.00	57.00	13.00
7	Mobile sub No. 2, OR	Distrib./unattended	115.00	57.00	13.00
8	Mobile Sub No. 3, OR	Distrib./unattended	115.00	57.00	12.50
9	Mobile Sub No. 4, OR	Distrib./unattended	115.00	57.00	13.00
10	Molalla, Molalla, OR	Distrib./unattended	57.00	13.00	
11	Mt. Angel, Mt. Angel, OR	Distrib./unattended	57.00	13.00	
12	Mt. Pleasant, Oregon City , OR	Distrib./unattended	115.00	13.00	
13	Multnomah, Portland, OR	Distrib./unattended	115.00	13.00	
14	Murrayhill, Beaverton, OR	Distrib./unattended	115.00	13.00	
15	Newberg, Newberg, OR	Distrib./unattended	115.00	13.00	
16	North Marion, near Woodburn, OR	Distrib./unattended	57.00	13.00	
17	North Plains, North Plains, OR	Distrib./unattended	57.00	13.00	
18	Northern, Portland, OR	Distrib./unattended	57.00	11.00	
19	Oak Hills, near Beaverton, OR	Distrib./unattended	115.00	13.00	
20	Oregon City - BPA, near Wilsonville, OR	Distrib./unattended	57.00		
21	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	57.00	13.00
22	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
23	Orient, near Gresham, OR	Distrib./unattended	57.00	13.00	
24	Oswego, Lake Oswego, OR	Distrib./unattended	115.00	13.00	
25	Oxford, Salem, OR	Distrib./unattended	115.00	13.00	
26	Pleasant Valley, near Portland, OR	Distrib./unattended	115.00	12.50	
27	Portsmouth, Portland, OR	Distrib./unattended	115.00	13.00	
28	Progress, near Tigard, OR	Distrib./unattended	115.00	13.00	
29	Raleigh Hills, near Portland, OR	Distrib./unattended	115.00	13.00	
30	Ramapo, near Portland, OR	Distrib./unattended	115.00	13.00	
31	Redland, near Oregon City, OR	Distrib./unattended	115.00	13.00	
32	Reedville, near Beaverton, OR	Distrib./unattended	115.00	13.00	
33	Rhodendron Switching, OR	Distrib./unattended	57.00		
34	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	13.00	
35	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	11.00	
36	Riverview, Portland, OR	Distrib./unattended	115.00	13.00	
37	Rockwood, near Gresham, OR	Distrib./unattended	115.00	13.00	
38	Rosemont, near Lake Oswego, OR	Distrib./unattended	115.00		
39	Roseway, Hillsboro, OR	Distrib./unattended	115.00	13.00	
40	Ruby, North, Gresham, OR	Distrib./unattended	57.00		

Name of Respondent Portland General Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/30/2012	Year/Period of Report End of 2010/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	Ruby, South, Gresham, OR	Distrib./unattended	57.00	13.00	
2	Salem-PGE, near Salem, OR	Distrib./unattended	57.00	13.00	
3	Sandy, Sandy, OR	Distrib./unattended	57.00	13.00	
4	Scappoose, Scappoose, OR	Distrib./unattended	115.00		
5	Scoggin, near Gaston, OR	Distrib./unattended	57.00	13.00	
6	Sellwood, Portland, OR	Distrib./unattended	115.00	57.00	13.00
7	Sellwood, Portland, OR	Distrib./unattended	115.00	13.00	
8	Sheridan, Sheridan, OR	Distrib./unattended	57.00	13.00	
9	Silverton, Silverton, OR	Distrib./unattended	57.00	13.00	
10	Six Corners, Six Corners, OR	Distrib./unattended	115.00	13.00	
11	Springbrook, Newberg, OR	Distrib./unattended	115.00	13.00	
12	Springdale, near Springdale, OR	Distrib./unattended		12.50	
13	St. Helens, near St. Helens, OR	Distrib./unattended	115.00		
14	St. Johns-BPA, near Portland, OR	Distrib./unattended		11.00	
15	St. Louis, St. Louis, OR	Distrib./unattended	57.00	13.00	
16	St. Marys, East Yard, near Beaverton, OR	Distrib./unattended	115.00	13.00	
17	Stephens, Portland, OR	Distrib./unattended	57.00	13.00	
18	Stephens, Portland, OR	Distrib./unattended	57.00	11.00	
19	Stephens, Portland, OR	Distrib./unattended	11.00	4.15	
20	Sullivan, West Linn, OR	Distrib./unattended	115.00	13.00	
21	Summit, Government Camp, OR	Distrib./unattended	57.00	13.00	
22	Summit, Government Camp, OR	Distrib./unattended	24.00	13.00	
23	Sunset, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
24	Swan Island, Portland, OR	Distrib./unattended	115.00	13.00	
25	Sylvan, near Portland, OR	Distrib./unattended	115.00	13.00	
26	Tabor, Portland, OR	Distrib./unattended	115.00	13.00	
27	Tabor, Portland, OR	Distrib./unattended	57.00		
28	Tektronix, Beaverton, OR	Distrib./unattended	115.00	13.00	
29	Tigard, Tigard, OR	Distrib./unattended	115.00	12.50	
30	Town Center, Portland, OR	Distrib./unattended	115.00	13.00	
31	Tualitin, Tualitin, OR	Distrib./unattended	115.00	13.00	
32	Twilight, Canby, OR	Distrib./unattended	57.00	13.00	
33	University, Salem, OR	Distrib./unattended	115.00	13.00	
34	Urban, Portland, OR	Distrib./unattended	115.00	13.00	
35	Waconda, near Hopmere, OR	Distrib./unattended	57.00	12.50	
36	Welches, near Welches, OR	Distrib./unattended	57.00	24.00	13.00
37	Welches, near Welches, OR	Distrib./unattended	57.00	13.00	
38	West Portland, Lower Yard, near Tigard, OR	Distrib./unattended	115.00		
39	West Portland, Upper Yard, near Tigard, OR	Distrib./unattended	115.00	13.00	
40	West Union, near Hillsboro, OR	Distrib./unattended	57.00	12.50	

Name of Respondent Portland General Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/30/2012	Year/Period of Report End of 2010/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	Willamina, near Willamina, OR	Distrib./unattended	57.00	13.00	
2	Willbridge, Portland, OR	Distrib./unattended	115.00	11.00	
3	Wilsonville, near Wilsonville, OR	Distrib./unattended	57.00	13.00	
4	Woodburn, Woodburn, OR	Distrib./unattended	57.00	13.00	
5	Yamhill, near Yamhill, OR	Distrib./unattended	57.00	13.00	
6					
7					
8					
9	Allston, BPA, near Mayger, OR	Transm./unattended	230.00		
10	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	13.00	
11	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	24.00	
12	Bethel, Salem, OR	Transm./unattended	230.00	115.00	13.00
13	Bethel, Salem, OR	Transm./unattended	115.00	57.00	13.00
14	Bethel, Salem, OR	Transm./unattended	115.00	13.00	
15	Biglow Canyon Windfarm	Transm./unattended	230.00	34.50	13.80
16	Blue Lake, Troutdale, OR	Transm./unattended	230.00	115.00	13.00
17	Blue Lake, Troutdale, OR	Transm./unattended	115.00	13.00	
18	Boardman, near Boardman, OR	Transm./unattended	500.00	24.00	
19	Boardman, OR	Transm./unattended	230.00	7.20	
20	Boardman, OR	Transm./unattended	24.00	7.20	
21	Broadview Subst. near Broadview, MT	Transm./unattended	500.00	230.00	
22	Carver, Carver, OR	Transm./unattended	230.00	115.00	13.00
23	Carver, Carver, OR	Transm./unattended	115.00	13.00	
24	Colstrip Plant, near Colstrip, MT	Transm./unattended	500.00	26.00	
25	Colstrip Subst. near Colstrip, MT	Transm./unattended	500.00	230.00	
26	Coyote Springs, Boardman, OR	Transm./unattended	500.00		
27	Faraday, Switchyard, OR	Transm./unattended	115.00	57.00	12.50
28	Faraday, Switchyard, OR	Transm./unattended	57.00	11.00	
29	Faraday Plant, near Estacada, OR	Transm./unattended	115.00	12.50	
30	Fort Rock, approx 12 mi NE of Silver Lake, OR	Transm./unattended	500.00		
31	Gresham, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
32	Grizzly, BPA, near Madras, OR	Transm./unattended	500.00		
33	Linneman, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
34	Malin, BPA, near Malin, OR	Transm./unattended	500.00		
35	McLoughlin, near Oregon City, OR	Transm./unattended	230.00	115.00	13.00
36	Monitor, near Monitor, OR	Transm./unattended	230.00	57.00	13.00
37	Murryhill, Beaverton, OR	Transm./unattended	230.00	115.00	13.00
38	North Fork, near Estacada, OR	Transm./unattended	115.00	13.00	
39	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	13.00	
40	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	11.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	11.00	
2	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	0.48	
3	Pearl, BPA, near Wilsonville, OR	Transm./unattended	230.00		
4	Pelton, near Madras , OR	Transm./unattended	230.00	13.00	
5	Pelton, near Madras, OR	Transm./unattended	13.00	13.00	
6	Port Westward, near Clatskanie, OR	Transm./unattended	230.00	18.00	16.50
7	River Mill, near Estacada, OR	Transm./unattended	57.00	11.00	
8	Rivergate North Yard, near Portland, OR	Transm./unattended	230.00	115.00	13.00
9	Round Butte, near Madras, OR	Transm./unattended	500.00	230.00	12.50
10	Round Butte, near Madras, OR	Transm./unattended	230.00	12.50	
11	Round Butte, near Madras, OR	Transm./unattended	230.00	66.00	12.50
12	Sand Springs, 22 mi E/22 mi S of Bend, OR	Transm./unattended	500.00		
13	Sherwood, near Six Corners, OR	Transm./unattended	230.00	115.00	13.00
14	St. Marys, West Yard, near Beaverton, OR	Transm./unattended	230.00	115.00	13.00
15	Sullivan, West Linn, OR	Transm./Unattended	57.00	4.15	
16	Sycan, 27 mi S of Silver Lake, OR	Transm./unattended	500.00		
17	Trojan, near Rainier, OR	Transm./unattended	230.00	12.50	
18					
19	TOTAL MVa		27044.00	4855.18	387.62
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
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	13,200	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		Capacitor Banks	2	6,000	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 Portland General Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/30/2012	Year/Period of Report End of 2010/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
50	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
43	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
56	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
84	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) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 05/30/2012	Year/Period of Report End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
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
15	1					6
19	1					7
29	1					8
35	1					9
42	2		Capacitor Banks	4	9,000	10
20	1		Capacitor Banks	3	15,000	11
45	2		Capacitor Banks	2	3,600	12
39	2		Capacitor Banks	3	9,600	13
56	2		Capacitor Banks	3	10,800	14
45	2		Capacitor Banks	4	12,000	15
31	3		Capacitor Banks	3	15,000	16
20	1		Capacitor Banks	4	18,000	17
28	2					18
56	2		Capacitor Banks	4	14,400	19
						20
280	2					21
78	3		Capacitor Banks	6	18,600	22
15	2					23
34	2		Capacitor Banks	2	7,200	24
50	2		Capacitor Banks	4	12,000	25
55	2		Capacitor Banks	2	6,000	26
28	1					27
50	2		Capacitor Banks	4	13,800	28
28	1		Capacitor Banks	2	6,600	29
17	1		Capacitor Banks	2	7,200	30
22	1					31
84	3		Capacitor Banks	6	18,000	32
						33
22	1		Capacitor Banks	2	7,200	34
22	1		Capacitor Banks	2	6,716	35
28	1		Capacitor Banks	2	6,000	36
78	3		Capacitor Banks	5	10,200	37
						38
28	1		Capacitor Banks	2	6,000	39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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.
15	2		Capacitor Banks	2	3,600	1
45	2		Capacitor Banks	4	14,400	2
28	1		Capacitor Banks	2	6,000	3
						4
13	2		Capacitor Banks	1	10,800	5
140	1		Capacitor Banks	1	24,000	6
28	1		Capacitor Banks	2	6,000	7
17	1		Capacitor Banks	3	19,200	8
33	3		Capacitor Banks	3	3,600	9
50	2		Capacitor Banks	4	12,000	10
56	2		Capacitor Banks	5	36,000	11
						12
			Capacitor Banks	1	24,000	13
						14
24	2		Capacitor Banks	2	7,200	15
56	2		Capacitor Banks	4	12,000	16
14	1					17
100	2		Capacitor Banks	2	16,800	18
25	6					19
50	2		Capacitor Banks	5	36,000	20
8	1					21
6	1					22
328	7		Capacitor Banks	14	70,800	23
50	2		Capacitor Banks	4	12,000	24
22	1		Capacitor Banks	2	6,000	25
22	1		Capacitor Banks	2	6,000	26
						27
56	2		Capacitor Banks	4	12,000	28
39	2		Capacitor Banks	4	7,200	29
56	2		Capacitor Banks	2	6,000	30
56	2		Capacitor Banks	4	13,200	31
28	1		Capacitor Banks	3	19,200	32
22	1		Capacitor Banks	2	7,200	33
112	4		Capacitor Banks	7	43,200	34
41	2		Capacitor Banks	2	6,000	35
6	1		Capacitor Banks	1	12,000	36
18	2		Capacitor Banks	2	6,600	37
			Capacitor Banks	1	24,000	38
56	2		Capacitor Banks	4	13,200	39
28	1		Capacitor Banks	3	15,200	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
24	2		Capacitor Banks	3	7,800	1
20	1					2
104	4		Capacitor Banks	6	18,000	3
42	2		Capacitor Banks	4	13,200	4
15	2		Capacitor Banks	1	1,800	5
						6
						7
						8
						9
464	4					10
170	1					11
502	2					12
140	1					13
28	1		Capacitor Banks	2	6,000	14
480	3					15
320	1					16
28	1		Capacitor Banks	2	6,000	17
685	3					18
55	1					19
55	1					20
80	3					21
640	2					22
56	2		Capacitor Banks	4	12,000	23
164	3					24
100	2					25
300	3					26
140	1					27
32	2					28
27	1					29
			Series Capacitor	1	363,000	30
572	2					31
						32
168	1					33
			Reactors	3	180,000	34
640	2					35
125	1					36
320	1					37
53	3	1				38
8	1					39
64	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/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.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
2	1					1
1	2					2
						3
164	4					4
3	1					5
450	3					6
32	2					7
520	4		Capacitor Banks	2	43,500	8
561	3		Reactors	12	180,000	9
372	3	2				10
22	1					11
			Series Capacitor	1	546,000	12
640	2					13
960	3		Capacitor Banks	3	108,000	14
33	1					15
			Series Capacitor	1	546,000	16
56	2					17
						18
17199	370	3		440	3,419,686	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 regulating equipment.

Schedule Page: 426 Line No.: 20 Column: a

Switching only. Identified locaton is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulation equipment.

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 regulation equipment.

Schedule Page: 426.2 Line No.: 20 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.: 33 Column: a

Switching only.

Schedule Page: 426.2 Line No.: 38 Column: a

Switching only.

Schedule Page: 426.2 Line No.: 40 Column: a

Switching only.

Schedule Page: 426.3 Line No.: 4 Column: a

Switching only. Distribution owned by CRPUD.

Schedule Page: 426.3 Line No.: 12 Column: a

Regulating only.

Schedule Page: 426.3 Line No.: 13 Column: a

Switching only. Distribution owned by CRPUD.

Schedule Page: 426.3 Line No.: 14 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.: 27 Column: a

Switching only.

Schedule Page: 426.3 Line No.: 38 Column: a

Switching only.

Schedule Page: 426.4 Line No.: 9 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.: 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 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.: 21 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.: 24 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.: 25 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.: 30 Column: a

Line compensation only.

Schedule Page: 426.4 Line No.: 32 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.: 34 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

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.: 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.: 5 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

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.: 12 Column: a

Line compensation only.

Schedule Page: 426.5 Line No.: 16 Column: a

Line compensation only.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2010/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3	Lease Payments for Corporate Headquarters	121 SW Salmon Street	418	4,973,098
4	OPUC Order No. 75-953	Corp.		
5				
6	Catering Services	Salmon Springs	921	634,348
7		Hospitality Group		
8				
9				
10				
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19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22	Administrative Services	Salmon Springs	186	727,482
23		Hospitality Group		
24				
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