THIS FILING IS		
Item 1: [X] 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** 2012/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 2012/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 121 SW Salmon Street, Portland, Oregon, 97204	
05 Name of Contact Person Kirk M. Stevens	06 Title of Contact Person Controller & Asst. Treasurer
07 Address of Contact Person *(Street, City, State, Zip Code)* 121 SW Salmon Street, Portland, Oregon, 97204	

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

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name James F. Lobdell	03 Signature James F. Lobdell	04 Date Signed *(Mo, Da, Yr)* 03/21/2013
02 Title SVP of Finance, 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.

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".

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

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)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	None
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	304	None
44	Sales of Electricity by Rate Schedules	310-311	
45	Sales for Resale	320-323	
46	Electric Operation and Maintenance Expenses	326-327	
47	Purchased Power	328-330	
48	Transmission of Electricity for Others	331	
49	Transmission of Electricity by ISO/RTOs	332	Not Applicable
50	Transmission of Electricity by Others	335	
51	Miscellaneous General Expenses-Electric	336-337	
52	Depreciation and Amortization of Electric Plant	350-351	
53	Regulatory Commission Expenses	352-353	
54	Research, Development and Demonstration Activities	354-355	
55	Distribution of Salaries and Wages	356	
56	Common Utility Plant and Expenses	397	None
57	Amounts included in ISO/RTO Settlement Statements	398	
58	Purchase and Sale of Ancillary Services	400	
59	Monthly Transmission System Peak Load	400a	
60	Monthly ISO/RTO Transmission System Peak Load	401	Not Applicable
61	Electric Energy Account	401	
62	Monthly Peaks and Output	402-403	
63	Steam Electric Generating Plant Statistics	406-407	
64	Hydroelectric Generating Plant Statistics	408-409	
65	Pumped Storage Generating Plant Statistics	410-411	None
66	Generating Plant Statistics Pages	422-423	

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".

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

GENERAL INFORMATION

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

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

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

Oregon - Incorporated July 25, 1930

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

Property of respondent was not so held during the year.

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

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

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

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

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

CONTROL OVER RESPONDENT

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

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	121 SW Salmon Street Corporation	Company has leased the	100	
2		headquarters complex in		
3		Portland, Oregon and sub-		
4		leases the complex to		
5		Respondent.		
6				
7	World Trade Center Northwest Corporation	Company is the holder of the	100	
8	(A wholly-owned subsidiary of 121 SW Salmon	World Trade Center Franchise		
9	Street Corporation)			
10				
11	Salmon Springs Hospitality Group	Company provides food	100	
12		catering services.		
13				
14	SunWay 1, LLC	Solar power generation	0.01	
15				
16	SunWay 2, LLC	Solar power generation	0.01	
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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	702,366
2	Senior Vice President, Finance, Chief Financial	Maria M. Pope	443,227
3	Officer, and Treasurer		
4	Vice President, General Counsel and Corporate	J. Jeffrey Dudley	322,628
5	Compliance Officer		
6	Vice President, Nuclear and Power Supply/Generation	Stephen M. Quennoz	299,535
7	Vice President, Power Operations and	James F. Lobdell	295,958
8	Resource Strategy		
9	Vice President, Administration	Arleen N. Barnett	255,978
10	Senior Vice President, Customer Service,	William O. Nicholson	277,437
11	Transmission and Distribution		
12	Vice President, Customer Strategies and	Carol A. Dillin	259,411
13	Business Development		
14	Vice President, Information Technology and	Campbell A. Henderson	221,448
15	Chief Information Officer		
16	Vice President, Distribution	O. Bruce Carpenter	228,026
17	Vice President, Public Policy	W. David Robertson	229,855
18	Vice President, Customer Service Operations	Kristin A. Stathis	184,438
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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.: 2 Column: b

On February 20, 2013, Maria M. Pope was appointed the Company’s Senior Vice President of Power Supply and Operations, and Resource Strategy. The appointment was effective March 1, 2013.

Schedule Page: 104 Line No.: 7 Column: b

On February 20, 2013, James F. Lobdell was appointed the Company’s Senior Vice President of Finance, Chief Financial Officer and Treasurer. The appointment was effective March 1, 2013.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Palm Beach, Florida
2	Private Investor, Retired from First Chicago NBD Corp.	
3	Rodney L. Brown, Jr.	Seattle, Washington
4	Managing Partner, Cascadia Law Group PLLC	
5	Jack E. Davis	Phoenix, Arizona
6	Retired Chief Executive Officer of	
7	Arizona Public Service Company	
8	David A. Dietzler	Lake Oswego, Oregon
9	Retired Partner of KPMG LLP	
10	Peggy Y. Fowler	Portland, Oregon
11	Retired Chief Executive Officer and President of	
12	Portland General Electric Company	
13	Kirby A. Dyess	Beaverton, Oregon
14	Principal, Austin Capital Management LLC	
15	Mark B. Ganz	Portland, Oregon
16	President and Chief Executive Officer of	
17	Cambia Health Solutions (formerly The Regence Group)	
18	Corbin A. McNeill, Jr.	Jackson Hole, Wyoming
19	Chair of the Board of Portland General Electric Company,	
20	Retired Chairman and co-Chief Executive Officer of	
21	Exelon Corp.	
22	Neil J. Nelson	Portland, Oregon
23	President and Chief Executive Officer of Siltronic Corp.	
24	M. Lee Pelton	Boston, Massachusetts
25	President of Emerson College	
26	James J. Piro	Portland, Oregon
27	President and Chief Executive Officer of	
28	Portland General Electric Company	
29	Robert T. F. Reid	Vancouver, British Columbia, Canada
30	Retired Chair and Corporate Director of British Columbia	
31	Transmission Corporation	
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Schedule Page: 105 Line No.: 5 Column: a

Appointed as a director of the Company on June 13, 2012.

Schedule Page: 105 Line No.: 10 Column: a

On January 14, 2012, Peggy Y. Fowler notified the Company that she would not stand for re-election to the Board of Directors at the Company's 2012 annual meeting of shareholders held on May 23, 2012.

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

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

Does the respondent have formula rates?

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

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on 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. Pursuant to PGE's application, the Federal Energy Regulatory Commission on December 28, 2011 issued an order in Docket No. ES12-04-000 that authorizes the Company to issue up to $700 million of short-term debt over the two-year period through February 6, 2014.

PGE has the following two unsecured revolving credit facilities as of December 31, 2012, that together provide a total of $700 million in available short-term financing: 1) a $300 million syndicated credit facility, which is scheduled to terminate in December 2016, and 2) a $400 million syndicated credit facility, which is scheduled to terminate in November 2017.

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, 2012, 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 Sheets with respect to these indemnities.

7. None

8. None

9. Legal Proceedings:

<u>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,</u> 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.

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, but in August 1993, the OPUC issued a Declaratory Ruling in PGE’s favor. 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. 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 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.

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. The court remanded the matter to the OPUC for reconsideration of its 1995 Order in light of the court's decision.

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

In March 2002, 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 in September 2008 that required PGE to refund $33.1 million to customers. The Company completed the distribution of the refund to customers, plus accrued interest, as required.

In October 2008, the URP and the Class Action Plaintiffs (described in the Dreyer proceeding below) separately appealed the September 2008 OPUC order to the Oregon Court of Appeals. On February 6, 2013, the Oregon Court of Appeals issued an opinion that upheld the September 2008 OPUC order.

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.

In January 2003, two class action suits were filed in Marion County Circuit Court against PGE. 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.

In April 2004, the Class Action Plaintiffs filed a Motion for Partial Summary Judgment and in July 2004, PGE also moved for Summary Judgment in its favor on all of the Class Action Plaintiffs' claims. In December 2004, the Judge granted the Class Action Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. In March 2005, PGE filed two Petitions with the Oregon Supreme Court asking the Court to take jurisdiction and command the trial Judge to dismiss the complaints, or to show cause why they should not be dismissed, and seeking to overturn the Class Certification.

In August 2006, the Oregon Supreme Court issued a ruling on PGE's Petitions 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.

In October 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.

In October 2007, the Class Action Plaintiffs filed a Motion with the Marion County Circuit Court to lift the abatement. In February 2009, the Circuit Court judge denied the Motion to lift the abatement.

<u>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</u>, 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).

In July 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 June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. Parties appealed various aspects of these FERC orders to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

In August 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. 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.

In October 2011, the FERC issued an Order on Remand establishing an evidentiary hearing to determine whether any seller had engaged in unlawful market activity in the Pacific Northwest spot markets during the December 25, 2000 through June 20, 2001 period by violating specific contracts or tariffs, and, if so, whether a direct connection existed between the alleged unlawful conduct and the rate charged under the applicable contract. The FERC held that the Mobile-Sierra public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under Mobile-Sierra that the rates charged under each contract are just and reasonable would have to be specifically overcome before a refund could be ordered. The FERC directed the presiding judge, if necessary, to determine a refund methodology and to calculate refunds, but held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Certain parties claiming refunds filed requests for rehearing of the Order on Remand, contesting, among other things, the applicable refund period reflected in the Order, the use of the Mobile-Sierra standard, any restraints in the Order on the type of evidence that could be introduced in the hearing, and the lack of market-wide remedy. The rehearing requests remain pending.

In December 2012, the FERC issued an order granting an interlocutory appeal of the trial judge's ruling on the scope of the remand proceeding. In this order, the FERC held that its Order on Remand was not intended to alter the general state of the law regarding the Mobile-Sierra presumption. The FERC also held that the Mobile-Sierra presumption could be overcome either by (i) a showing that a respondent had violated a contract or tariff and that the violation had a direct connection to the rate charged under the applicable contract or (ii) a showing that the contract rate at issue imposed an excessive burden or seriously harmed the public interest.

In its October 2011 Order on Remand, the FERC held the hearing procedures in abeyance pending the results of settlement discussions, which it ordered be convened before a FERC settlement judge. Pursuant to the settlement proceedings, the Company received notice of two claims and has reached agreements to settle both of these claims for an immaterial amount. The FERC approved both settlements during 2012.

In May 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 20, 2001. The settlement with the California parties did not resolve potential claims from other market participants relating to transactions in the Pacific Northwest.

The above-referenced settlements resulted in a release of the Company as a named respondent in the ongoing remand proceedings, which are limited to initial and direct claims for refunds, but there remains a possibility that additional claims could be asserted against the Company in future proceedings if refunds are ordered against current respondents.

10. None

11. (Reserved)

12. None

13. Changes in Directors and Officers:

On January 14, 2012, Peggy Y. Fowler, a member of the Board of Directors of Portland General Electric Company, notified the Company that she would not stand for re-election to the Board of Directors at the Company’s 2012 annual meeting of shareholders held on May 23, 2012. Ms. Fowler was a member of the Finance Committee of the Company’s Board of Directors.

On June 13, 2012, the Board of Directors of Portland General Electric Company appointed Jack E. Davis as a director of the Company to serve until the next annual meeting of shareholders. The Board of Directors also appointed Mr. Davis to serve on the Finance Committee.

On February 20, 2013, the board of directors of Portland General Electric Company appointed Maria M. Pope as the Company’s Senior Vice President of Power Supply and Operations, and Resource Strategy, and James F. Lobdell as the Company’s Senior Vice President of Finance, Chief Financial Officer and Treasurer. Both appointments were effective March 1, 2013.

14. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	6,806,135,364	6,590,485,297
3	Construction Work in Progress (107)	200-201	140,303,251	119,814,163
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,946,438,615	6,710,299,460
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,250,583,440	3,067,218,653
6	Net Utility Plant (Enter Total of line 4 less 5)		3,695,855,175	3,643,080,807
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)		3,695,855,175	3,643,080,807
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		28,250,053	27,661,733
19	(Less) Accum. Prov. for Depr. and Amort. (122)		12,977,481	12,475,809
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	3,722,671	2,892,279
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	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		70,949,452	73,642,418
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		2,562,521	831
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		92,507,216	91,721,452
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		11,578,489	4,968,250
36	Special Deposits (132-134)		45,558,970	80,219,447
37	Working Fund (135)		25,367	25,695
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		117,278,145	120,966,271
41	Other Accounts Receivable (143)		40,152,976	28,273,762
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,300,261	5,587,219
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		287,260	104,437
45	Fuel Stock (151)	227	39,663,607	33,794,768
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	33,167,801	32,662,190
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	6,081
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	252,288	360,000

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	4,817,251	4,659,816
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)		53,874,917	58,237,421
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)		96,665,402	101,146,935
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		6,078,475	19,409,497
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		2,562,521	831
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		441,538,166	479,246,520
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		9,181,075	11,251,311
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	3,402,786	987,024
72	Other Regulatory Assets (182.3)	232	645,926,821	784,667,938
73	Prelim. Survey and Investigation Charges (Electric) (183)		13,145,091	9,587,602
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)		178,997	197,376
77	Temporary Facilities (185)		57,891	9,498
78	Miscellaneous Deferred Debits (186)	233	14,170,614	15,752,414
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)		21,958,086	28,021,674
82	Accumulated Deferred Income Taxes (190)	234	339,534,982	387,648,270
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,047,556,343	1,238,123,107
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,277,456,900	5,452,171,886

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2012/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	832,388,455	828,591,553
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	16,366,513	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	7,776,148	8,076,622
11	Retained Earnings (215, 215.1, 216)	118-119	893,192,136	833,609,596
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-135,601	-214,993
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)	-6,376,798	-6,078,989
16	Total Proprietary Capital (lines 2 through 15)		1,727,658,557	1,663,132,619
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,636,400,000	1,736,400,000
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	101,817	107,806
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		880,399	1,099,639
24	Total Long-Term Debt (lines 18 through 23)		1,635,621,418	1,735,408,167
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)		7,939,406	8,834,000
29	Accumulated Provision for Pensions and Benefits (228.3)		354,789,256	300,067,805
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		7,905,584	20,017,327
32	Long-Term Portion of Derivative Instrument Liabilities		72,963,408	171,648,800
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		93,721,755	87,194,723
35	Total Other Noncurrent Liabilities (lines 26 through 34)		537,319,409	587,762,655
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		16,999,434	29,997,975
38	Accounts Payable (232)		180,099,242	181,211,138
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		425,485	582,855
41	Customer Deposits (235)		13,781,610	8,523,369
42	Taxes Accrued (236)	262-263	17,799,529	9,627,185
43	Interest Accrued (237)		22,696,098	23,678,160
44	Dividends Declared (238)		21,322,540	21,035,952
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2012/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		11,354,877	12,344,347
48	Miscellaneous Current and Accrued Liabilities (242)		13,961,668	9,569,472
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		199,714,587	387,235,892
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		72,963,408	171,648,800
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)		425,191,662	512,157,545
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	0	0
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	1,596,555	1,252,868
60	Other Regulatory Liabilities (254)	278	73,382,141	68,548,059
61	Unamortized Gain on Reaquired Debt (257)		82,533	90,585
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		597,926,639	553,945,938
64	Accum. Deferred Income Taxes-Other (283)		278,677,986	329,873,450
65	Total Deferred Credits (lines 56 through 64)		951,665,854	953,710,900
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,277,456,900	5,452,171,886

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	1,823,171,165	1,832,467,476		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,050,371,588	1,087,126,410		
5	Maintenance Expenses (402)	320-323	116,283,095	112,230,964		
6	Depreciation Expense (403)	336-337	222,779,529	211,052,942		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	2,906,607	3,119,928		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	21,547,511	19,275,881		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		3,500,396	3,500,278		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		15,321,396	9,627,903		
13	(Less) Regulatory Credits (407.4)		21,047,348	23,315,749		
14	Taxes Other Than Income Taxes (408.1)	262-263	101,046,406	96,561,192		
15	Income Taxes - Federal (409.1)	262-263	16,674,750	1,994,642		
16	- Other (409.1)	262-263	482,682	357,919		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	301,377,302	299,660,928		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	254,055,178	242,341,993		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)		12,796			
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		1,792,958	662,783		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,578,994,490	1,579,514,028		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		244,176,675	252,953,448		

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

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
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)	
						1
1,823,171,165	1,832,467,476					2
						3
1,050,371,588	1,087,126,410					4
116,283,095	112,230,964					5
222,779,529	211,052,942					6
2,906,607	3,119,928					7
21,547,511	19,275,881					8
						9
3,500,396	3,500,278					10
						11
15,321,396	9,627,903					12
21,047,348	23,315,749					13
101,046,406	96,561,192					14
16,674,750	1,994,642					15
482,682	357,919					16
301,377,302	299,660,928					17
254,055,178	242,341,993					18
						19
						20
12,796						21
						22
						23
1,792,958	662,783					24
1,578,994,490	1,579,514,028					25
244,176,675	252,953,448					26

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

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		244,176,675	252,953,448		
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)		225,478	202,114		
33	Revenues From Nonutility Operations (417)		3,636,103	3,574,305		
34	(Less) Expenses of Nonutility Operations (417.1)		3,151,534	2,794,300		
35	Nonoperating Rental Income (418)		1,278,410	1,898,239		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	479,392	401,918		
37	Interest and Dividend Income (419)		105,780	151,105		
38	Allowance for Other Funds Used During Construction (419.1)		6,067,376	4,625,954		
39	Miscellaneous Nonoperating Income (421)		1,064,528	-1,974,107		
40	Gain on Disposition of Property (421.1)		-90,406	21,900		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		9,164,171	5,702,900		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		4,864	31,376		
45	Donations (426.1)		1,807,987	1,829,376		
46	Life Insurance (426.2)		-1,942,614	326,324		
47	Penalties (426.3)		14,456	254,500		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		725,643	902,093		
49	Other Deductions (426.5)		3,016,725	-966,604		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		3,627,061	2,377,065		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,146,300	1,114,948		
53	Income Taxes-Federal (409.2)	262-263	-1,114,917	-186,639		
54	Income Taxes-Other (409.2)	262-263	-13,115	-59,910		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	2,451,443	1,082,256		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,062,663	2,915,884		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)			14,052		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		407,048	-979,281		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		5,130,062	4,305,116		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		99,124,496	104,254,149		
63	Amort. of Debt Disc. and Expense (428)		2,294,416	2,544,142		
64	Amortization of Loss on Reaquired Debt (428.1)		6,068,563	2,501,553		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		8,052	8,052		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		4,210,794	4,181,275		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		3,699,361	3,058,885		
70	Net Interest Charges (Total of lines 62 thru 69)		107,990,856	110,414,182		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		141,315,881	146,844,382		
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)		141,315,881	146,844,382		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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		829,756,801	763,311,385
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)		140,836,489	146,442,464
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	238	-81,653,949	(79,997,048)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-81,653,949	(79,997,048)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		400,000	
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		889,339,341	829,756,801
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		3,852,795	3,852,795
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,852,795	3,852,795
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		893,192,136	833,609,596
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-214,993	(616,911)
50	Equity in Earnings for Year (Credit) (Account 418.1)		479,392	401,918
51	(Less) Dividends Received (Debit)		400,000	
52				
53	Balance-End of Year (Total lines 49 thru 52)		-135,601	(214,993)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	141,315,881	146,844,382
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	247,233,647	233,448,751
5	Amortization of Debt Discount	8,354,927	5,037,643
6	Amortization of Unrecovered Plant	3,500,396	3,500,278
7	Net Asset from Price Risk Management Activities	-174,190,283	7,322,701
8	Deferred Income Taxes (Net)	47,710,904	55,485,307
9	Investment Tax Credit Adjustment (Net)		-14,052
10	Net (Increase) Decrease in Receivables	-4,179,336	-18,288,066
11	Net (Increase) Decrease in Inventory	-6,418,092	-15,882,306
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	4,931,546	5,168,124
14	Net (Increase) Decrease in Other Regulatory Assets	176,573,309	69,221,596
15	Net Increase (Decrease) in Other Regulatory Liabilities	-2,885,465	-14,707,729
16	(Less) Allowance for Other Funds Used During Construction	6,067,376	4,625,954
17	(Less) Undistributed Earnings from Subsidiary Companies	479,392	401,918
18	Contribution to the voluntary employee's beneficiary association trust	-2,195,378	-15,378,088
19	Contribution to Pension Plan		-26,000,000
20	Other: Margin and Customer Deposits	39,918,718	5,106,755
21	Other Operating	23,114,144	12,745,797
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	496,238,150	448,583,221
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-302,421,677	-306,835,673
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-588,320	-598,937
30	(Less) Allowance for Other Funds Used During Construction	-6,067,376	-4,625,954
31	Other (provide details in footnote):		
32	Other Capital Expenditures	-6,834,667	4,540,134
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-303,777,288	-298,268,522
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Sale of Utility Property	9,750,000	
39	Investments in and Advances to Assoc. and Subsidiary Companies	-271,608	-401,509
40	Contributions and Advances from Assoc. and Subsidiary Companies	400,000	
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	2,647,014	2,589,857
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	-25,501,801	-49,698,939
54	Sales of Trojan Decommissioning Trust Securities	22,807,578	46,326,879
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-293,946,105	-299,452,234
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		10,998,887
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)		10,998,887
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-100,005,989	-72,605,980
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Premium paid on repayment of long-term debt		-7,279,650
78	Net Decrease in Short-Term Debt (c)	-12,998,541	
79	Debt Issuance Costs	-1,318,750	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-81,358,854	-79,091,295
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-195,682,134	-147,978,038
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	6,609,911	1,152,949
87			
88	Cash and Cash Equivalents at Beginning of Period	4,993,945	3,840,996
89			
90	Cash and Cash Equivalents at End of period	11,603,856	4,993,945

Schedule Page: 120 Line No.: 38 Column: b

In January 2012, PGE completed construction of a $10 million, 1.75 MW solar powered electric generating facility, which was sold to, and simultaneously leased-back from, a financial institution. The Company operates the facility and receives 100% of the power generated by the facility.

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)	$ 4,968,250	$11,578,489
Working Funds (135)	25,695	25,367
Temporary Cash Investment (136)	-	-
	$ 4,993,945	$11,603,856

	2011	2012
Cash paid during the year:		
Interest	$ 106,404,391	$ 100,320,282
AFDC - Borrowed	(3,058,885)	(3,699,361)
	$ 103,345,506	$ 96,620,921
Income taxes	$ 3,428,888	$ 13,401,781
Non-cash investing and financing activities:		
Accrued capital additions	$ 18,829,554	$ 18,547,538
Accrued dividends payable	21,035,952	21,332,540
Preliminary engineering transferred to Construction work in progress from Other noncurrent assets	7,746,176	-

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, 2012, PGE served 828,354 retail customers with a service area population of approximately 1.7 million, comprising approximately 44% of the state’s population.

As of December 31, 2012, PGE had 2,603 employees, with 809 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 775 and 34 employees and expire in February 2015 and August 2014, 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, issuances 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, as determined by the OPUC. 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 Sheets 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 Statements 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 Statements of Income but are recorded within Operating Expenses in financial statements prepared in accordance with GAAP.

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 gain or loss contingencies, as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ materially 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, of which PGE had none as of December 31, 2012 and 2011.

Accounts Receivable

Accounts receivable are recorded at invoiced amounts and do not bear interest when recorded. Late payment fees on balances in arrears are first assessed 16 business days after the due date. An inactive account balance is charged-off in the period in which the receivable is deemed uncollectible, but no sooner than 45 business 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, natural gas, oil and foreign currency. 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, 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 manage exposure to volatility in net power costs for the Company's retail customers.

In accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE recognizes a regulatory asset or liability to defer unrealized losses or gains, respectively, on derivative instruments until settlement. At the time of settlement, PGE recognizes a realized gain or loss on the derivative instrument. Contracts that qualify for the normal purchases and normal sales exception are not required to be recorded at fair value.

Physical electricity sale and purchase transactions 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 collateral with certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are classified as Special deposits in the accompanying balance sheets and were $46 million and $80 million as of December 31, 2012 and 2011, respectively. Letters of credit provided as collateral are not recorded on the Company's balance sheet and were $45 million and $104 million as of December 31, 2012 and 2011, respectively.

Inventories

PGE's inventories, which are 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. Periodically, the Company assesses the realizability of inventory for purposes of determining that inventory is recorded at the lower of average cost or market.

Electric Utility Plant

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 an allowance for funds used during construction (AFDC). Plant replacements are capitalized, with minor items charged to expense as incurred. Periodic major maintenance inspections and overhauls at the Company's generating plants are charged to expense as incurred, subject to regulatory accounting as applicable. 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.

During the period of construction, costs expected to be included in the final value of the constructed asset, and depreciated once the asset is complete and placed in service, are classified as Construction work in progress in Electric utility plant on the balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any 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.

PGE records AFDC, which is intended to represent the Company's cost of funds used for construction purposes and is based on the rate granted in the latest general rate case for equity funds and the cost of actual borrowings for debt funds. AFDC is capitalized as part of the cost of plant and credited to the statements of income. The average rate used by PGE was 7.5% in 2012 and 7.8% in 2011. AFDC from borrowed funds was $4 million in 2012 and $3 million in 2011 and is reflected as a reduction to Interest expense. AFDC from equity funds was $6 million in 2012 and $5 million in 2011 and is reflected as a component of Other income, net.

Costs which are disallowed for recovery in customer prices are charged to expense at the time such disallowance is probable.

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 3.8% in 2012 and 3.7% in 2011. Estimated asset retirement removal costs included in depreciation expense were $55 million for the year ended December 31, 2012 and $49 million in 2011.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of 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. In September 2010, PGE received an order from the OPUC authorizing new depreciation rates to be effective January 2011.

Thermal production plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the estimated retirement dates, which range from 2020 to 2050. Depreciation is provided on the Company's other classes of plant in service over their estimated average service lives, which are as follows (in years):

Production, excluding thermal:	
Hydro	87
Wind	27
Transmission	53
Distribution	40
General	13

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 recorded against AROs or to accumulated depreciation.

In June 2011, PGE received an order from the OPUC authorizing an increase in customer prices effective July 1, 2011 for depreciation expense and decommissioning costs related to the Company's commitment to cease coal-fired operations at Boardman at the end of 2020.

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 $151 million and $153 million as of December 31, 2012 and 2011, respectively, with amortization expense of $22 million in 2012 and $19 million in 2011. Future estimated amortization expense as of December 31, 2012 is as follows: $20 million in 2013; $18 million in 2014; $16 million in 2015; $14 million in 2016; and $11 million in 2017.

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, 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 actual or estimated 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 (i) increased competition that restricts the Company's ability to establish prices to recover specific costs, and (ii) 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, management believes that recovery of the Company's regulatory assets is probable.

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 customer prices to reflect a portion of the difference between each year's forecasted net variable power costs (NVPC) included in customer prices (baseline NVPC) and actual NVPC. PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and baseline NVPC by application of an asymmetrical "deadband," which ranges from $15 million below to $30 million above baseline NVPC. If the difference between actual NVPC, as determined pursuant to the PCAM, and baseline NVPC falls within the established deadband range, PGE absorbs the incremental cost or benefit, with any difference falling outside the lower and upper thresholds of the deadband range being shared 90/10 between customers and the Company, respectively. Any customer refund or collection is also subject to a regulated earnings test. A refund occurs 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 authorized ROE. A collection occurs to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. PGE's authorized ROE was 10% for 2012 and 2011. A final determination of any customer refund or collection is made in the following year by the OPUC through a 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 higher end of 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 established deadband, a regulatory asset is recorded for any future amount due from retail customers, with offsetting amounts recorded to Revenues.

For 2012, actual NVPC was below baseline NVPC by $17 million, and exceeded the lower deadband threshold of $15 million. However, based on results of the regulated earnings test, no estimated refund to customers was recorded as of December 31, 2012. A final determination regarding the 2012 PCAM results will be made by the OPUC through a public filing and review in 2013.

For 2011, actual NVPC was below baseline NVPC by $34 million, and exceeded the lower deadband threshold of $15 million. PGE recorded an estimated refund to customers of $10 million, reduced from the $17 million potential refund to customers as a result of the regulated earnings test. A final determination regarding the 2011 PCAM results was made by the OPUC through a public filing and review in 2012, which, based upon the application of an updated regulated earnings test, resulted in a revised refund to customers of $6 million to be returned to customers over a one-year period beginning January 1, 2013.

Asset Retirement Obligations

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. Due to the long lead time involved until decommissioning activities occur, the Company uses present value techniques because 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. Loss contingencies are accrued, and disclosed if material, 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 reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case 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.

A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be reasonably estimated, disclosure of the loss contingency includes a statement to that effect and the reasons.

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) presented on the balance sheets is comprised of the difference between the non-qualified benefit plans' obligations recognized in net income and the unfunded position.

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 $42 million in 2012 and $41 million in 2011.

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 $80 million and $87 million as of December 31, 2012 and 2011, respectively, and will be included in prices when the temporary differences reverse.

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, net, respectively, in the statements of income.

Recent Accounting Pronouncements

Accounting Standards Update (ASU) 2011-04, *Fair Value Measurements and Disclosures (Topic 820) - Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (ASU 2011-04) changed the wording used to describe principles and requirements to align with International Financial Reporting Standards as issued by the International Accounting Standards Board, and were not intended to change the application of Topic 820. Some of the amendments clarify the Financial Accounting Standards Board's intent on the application of existing fair value guidance or change a particular principle or requirement for measuring fair value or fair value disclosures. The amendments in ASU 2011-04 are to be applied prospectively and are effective for interim and annual periods beginning after December 15, 2011 for public entities, with early application not permitted. PGE adopted the amendments contained in ASU 2011-04 on January 1, 2012, which did not have an impact on the Company's financial position, results of operations, or cash flows.

ASU 2011-11, *Balance Sheet (Topic 210) - Disclosures about Offsetting Assets and Liabilities* (ASU 2011-11) requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. The amendments in ASU 2011-11 are to be applied for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. Disclosures required by ASU 2011-11 shall be provided retrospectively for all comparative periods presented. PGE will adopt the amendments contained in ASU 2011-11 on January 1, 2013, which is not expected to have an impact on the Company'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,	
	2012	**2011**
Balance as of beginning of year	$ 6	$ 5
Increase in provision	6	11
Amounts written off, less recoveries	(7)	(10)
Balance as of end of year	**$ 5**	**$ 6**

Trust Accounts

PGE maintains two trust accounts as follows:

Nuclear decommissioning trust—Reflects assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) and represent amounts collected from customers less qualified expenditures plus any realized and unrealized gains and losses on the investments held therein.

Non-qualified benefit plan trust—Reflects assets held in trust to cover the obligations of PGE's non-qualified benefit plans and represents contributions made by the Company less qualified expenditures plus any realized and unrealized gains and losses on the investment held therein.

The trusts are comprised of the following investments as of December 31 (in millions):

	Nuclear Decommissioning Trust		Non-Qualified Benefit Plan Trust	
	2012	**2011**	**2012**	**2011**
Cash equivalents	$ 15	$ 14	$ 2	$ —
Marketable securities, at fair value:				
Equity securities	—	—	5	10
Debt securities	23	23	2	3
Insurance contracts, at cash surrender value	—	—	23	23
	$ 38	$ 37	$ 32	$ 36

For information concerning the fair value measurement of those assets recorded at fair value held in the trusts, see Note 4, Fair Value of Financial Instruments.

Other Noncurrent 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 Construction work in progress within 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, 2012 and 2011, PGE has recorded preliminary engineering costs of $14 million and $10 million, respectively. For the years ended December 31, 2012 and 2011, no material preliminary engineering costs were expensed.

NOTE 4: FAIR VALUE OF FINANCIAL INSTRUMENTS

PGE determines the fair value of financial instruments, both assets and liabilities recognized and not recognized in the Company's balance sheets, for which it is practicable to estimate fair value as of December 31, 2012 and 2011, and then classifies these financial assets and liabilities based on a fair value hierarchy. The 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.

Level 2 Pricing inputs include those that are directly or indirectly observable in the marketplace as of the reporting date.

Level 3 Pricing inputs include significant inputs which are unobservable for the asset or liability.

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.

PGE recognizes transfers between levels in the fair value hierarchy as of the end of the reporting period for all of its financial instruments. Changes to market liquidity conditions, the availability of observable inputs, or changes in the economic structure of a security marketplace may require transfer of the securities between levels. There were no significant transfers between levels during each of the years ended December 31, 2012, and 2011, except those net transfers out of Level 3 to Level 2 presented in this note.

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, 2012			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Nuclear decommissioning trust (1):				
Money market funds	$ —	$ 15	$ —	$ 15
Debt securities:				
Domestic government	7	8	—	15
Corporate credit	—	8	—	8
Non-qualified benefit plan trust (2):				
Money market funds	—	2	—	2
Equity securities:				
Domestic	2	2	—	4
International	1	—	—	1
Debt securities - domestic government	2	—	—	2
Assets from price risk management activities (1) (3):				
Electricity	—	1	—	1
Natural gas	—	3	2	5
	$ 12	$ 39	$ 2	$ 53
Liabilities - Liabilities from price risk management activities (1) (3):				
Electricity	$ —	$ 72	$ 10	$ 82
Natural gas	—	110	8	118
	$ —	$ 182	$ 18	$ 200

(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 of $23 million, which are recorded at cash surrender value.
(3) For further information, see Note 5, Price Risk Management.

	As of December 31, 2011			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Nuclear decommissioning trust (1):				
Money market funds	$ —	$ 14	$ —	$ 14
Debt securities:				
Domestic government	3	9	—	12
Corporate credit	—	11	—	11
Non-qualified benefit plan trust (2):				
Equity securities:				
Domestic	7	2	—	9
International	1	—	—	1
Debt securities - domestic government	3	—	—	3
Assets from price risk management activities (1) (3):				
Electricity	—	2	—	2
Natural gas	—	17	—	17
	$ 14	$ 55	$ —	$ 69
Liabilities - Liabilities from price risk management activities (1) (3):				
Electricity	$ —	$ 108	$ 29	$ 137
Natural gas	—	201	50	251
	$ —	$ 309	$ 79	$ 388

(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 of $23 million, which are recorded at cash surrender value.
(3) For further information, see Note 5, Price Risk Management.

Trust assets held in the Nuclear decommissioning and Non-qualified benefit plan trusts are recorded at fair value in PGE's balance sheets and invested in securities that are exposed to interest rate, credit and market volatility risks. These assets are classified within Level 1, 2 or 3 based on the following factors:

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, certificates of deposits, and commercial paper. Money market funds are classified as Level 2 in the fair value hierarchy as the securities are traded in active markets of similar securities but are not directly valued using quoted market prices.

Debt securities—PGE invests in highly-liquid United States treasury securities to support the investment objectives of the trusts. These domestic government securities are classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the reporting date.

Assets classified as Level 2 in the fair value hierarchy include domestic government debt securities, such as municipal debt, and corporate credit securities. Prices are determined by evaluating pricing data such as broker quotes for similar securities and adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation as applicable.

Equity securities—Equity mutual fund and common stock securities are primarily classified as Level 1 in the fair value hierarchy due to the availability of quoted prices for identical assets in an active market as of the reporting date. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange (NYSE). Certain mutual fund assets included in commingled trusts or separately managed accounts are classified as Level 2 in the fair value hierarchy as pricing inputs are directly or indirectly observable in the marketplace.

Assets and liabilities from price risk management activities are recorded at fair value in PGE's balance sheets and consist of derivative instruments entered into by the Company to manage its exposure to commodity price risk and foreign currency exchange rate risk, and reduce volatility in net power costs for the Company's retail customers. For additional information regarding these assets and liabilities, see Note 5, Price Risk Management.

For those assets and liabilities from price risk management activities classified as Level 2, fair value is derived using present value formulas that utilize inputs such as quoted forward prices for commodities and interest rates. 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 over-the-counter forwards, commodity futures and swaps.

Assets and liabilities from price risk management activities classified as Level 3 consist of instruments for which fair value is derived using one or more significant inputs that are not observable for the entire term of the instrument. These instruments consist of longer term over-the-counter swap derivatives. Commodity option contracts whose fair value is derived using standardized valuation techniques, such as Black-Scholes, are also classified as Level 3. Inputs into the valuation of commodity option contracts include forward commodity prices, forward interest rates, and historic volatility and correlation factors.

The Company values its Level 3 assets and liabilities from price risk management activities using a discounted cash flow valuation technique in which quoted forward prices for the respective commodity are significant unobservable inputs. Quantitative information regarding the significant, unobservable inputs used in the measurement of Level 3 assets and liabilities from price risk management activities as of December 31, 2012 is presented below:

		Range and Weighted Average Price per Unit			
	Fair Value	**Low**	**High**	**Weighted Average**	**Unit**
Assets from price risk management activities:	(in millions)				
Natural gas financial swaps	$ 2	$ 3.74	$ 5.21	$ 4.36	Dth
Liabilities from price risk management activities:					
Electricity financial swaps and commodity futures	10	7.12	51.72	41.14	MWh
Natural gas financial swaps	8	3.67	5.21	4.20	Dth

Long-term forward prices for commodity derivatives employ the mid-point of the market's bid-ask spread and are derived using observed transactions in active markets, as well as historical experience as a participant in those markets.

The Company's Risk Management department, which reports to the Chief Financial Officer, prepares valuations for all derivative transactions. This process includes management of the mark-to-market process, which ultimately determines the fair value measurement for assets and liabilities from price risk management activities. On a daily basis, mark-to-market valuations for derivatives are calculated using the Company's system of record. Inputs used in performing daily mark-to-market calculations are uploaded into the system of record after review for reasonableness against expectations and subsequent to validation against broker quotes and market data from a regulated exchange. In addition, the overall change in mark-to-market is evaluated based on pricing input expectations. Any discrepancies identified during this process may result in adjustment of an input.

PGE's Level 3 assets and liabilities from price risk management activities are sensitive to market price changes in the respective underlying commodities. The significance of the impact is dependent upon the magnitude of the price change and the Company's position as either the buyer or seller of the contract. As the buyer of a commodity financial swap, an increase in the underlying commodity price would result in a favorable change to the fair value measurement. Conversely, a decrease in the underlying commodity price would result in an unfavorable change to the fair value measurement. As the seller of a commodity financial swap, the fair value measurements are sensitive to price changes in a manner opposite to the buy side relationship discussed above.

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

	Years Ended December 31,	
	2012	2011
Net liabilities from price risk management activities as of beginning of year	$ 79	$ 120
Net realized and unrealized losses	15 (1)	86
Purchases	(1)	3
Issuances	(1)	—
Settlements	—	(1)
Net transfers out of Level 3 to Level 2	(76)	(129)
Net liabilities from price risk management activities as of end of year	$ 16	$ 79
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 14	$ 88

(1) Includes $1 million of realized losses, net.

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.

Long-term debt is recorded at amortized cost in PGE's balance sheets. The fair value of long-term debt is classified as a Level 2 fair value measurement and 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, 2012, the estimated aggregate fair value of PGE's long-term debt was $1,949 million, compared to its $1,636 million carrying amount. As of December 31, 2011, the estimated aggregate fair value of PGE's long-term debt was $2,091 million, compared to its $1,735 million carrying amount.

For fair value information concerning the Company's pension plan assets, see Note 10, Employee Benefits.

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 in its wholesale electric utility activities to manage its exposure to commodity price risk and foreign exchange rate risk in order to manage volatility in net power costs for its retail customers. These derivative instruments may include forward, futures, swap, and option contracts for electricity, natural gas, oil and foreign currency, which are recorded at fair value on the balance sheets, 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 settlement of the associated derivative instrument. 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 to report gross on the balance sheets the positive and negative exposures resulting from derivative instruments entered into with counterparties where a master netting arrangement exists. As of December 31, 2012 and 2011, the Company had $18 million and $26 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 2016, were as follows (in millions):

	As of December 31,					
	2012			2011		
Commodity contracts:						
Electricity		11	MWh		13	MWh
Natural gas		86	Decatherms		79	Decatherms
Foreign currency exchange	$	7	Canadian	$	6	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,	
	2012	2011
Current assets:		
Commodity contracts:		
Electricity	$ 1	$ 2
Natural gas	3	17
Total current derivative assets	4	19
Noncurrent assets:		
Commodity contracts:		
Natural gas	2	—
Total derivative assets not designated as hedging instruments	$ 6	$ 19
Total derivative assets	$ 6	$ 19
Current liabilities:		
Commodity contracts:		
Electricity	$ 44	$ 66
Natural gas	83	150
Total current derivative liabilities	127	216
Noncurrent liabilities:		
Commodity contracts:		
Electricity	38	71
Natural gas	35	101
Total noncurrent derivative liabilities	73	172
Total derivative liabilities not designated as hedging instruments	$ 200	$ 388
Total derivative liabilities	$ 200	$ 388

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,	
	2012	2011
Commodity contracts:		
Electricity	$ 56	$ 117
Natural Gas	19	98

Net unrealized losses and certain net realized 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, 2012, and 2011, $42 million, and $192 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, 2012 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2013	2014	2015	Total
Commodity contracts:				
Electricity	$ 43	$ 28	$ 10	$ 81
Natural gas	80	27	6	113
Net unrealized loss	$ 123	$ 55	$ 16	$ 194

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, 2012 was $163 million, for which the Company had $45 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, 2012, the cash requirement to either post as collateral or settle the instruments immediately would have been $157 million.

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

	As of December 31,	
	2012	2011
Assets from price risk management activities:		
Counterparty A	21%	19%
Counterparty B	13	2
Counterparty C	11	16
Counterparty D	10	9
Counterparty E	6	13
	61%	59%
Liabilities from price risk management activities:		
Counterparty F	24%	23%
Counterparty G	14	10
Counterparty H	10	6
	48%	39%

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 (1)	As of December 31, 2012	2011
Regulatory assets:			
Price risk management (2)	2 years	$ 194	$ 365
Pension and other postretirement plans (2)	(3)	321	295
Deferred income taxes (2)	(4)	84	91
Deferred broker settlements (2)	1 year	20	11
Deferred capital projects	(5)	16	—
Other (6)	Various	11	23
Total regulatory assets		$ 646	$ 785
Regulatory liabilities:			
Asset retirement obligations (7)	(4)	$ 39	$ 36
Other (8)	Various	34	33
Total regulatory liabilities		$ 73	$ 69

(1) As of December 31, 2012.
(2) Does not include a return on investment.
(3) Recovery expected over the average service life of employees. For additional information, see Note 2, Summary of Significant Accounting Policies.
(4) Recovery expected over the estimated lives of the assets.
(5) Recovery period not yet determined.
(6) Of the total other unamortized regulatory asset balances, a return is recorded on $11 million and $21 million as of December 31, 2012 and 2011, respectively.
(7) Included in rate base for ratemaking purposes.
(8) Other includes $10 million related to the Residential Exchange Program and $7 million related to Trojan ISFSI pollution control tax credits for 2011 which were previously disclosed separately in the 2011 Notes to Financial Statements.

As of December 31, 2012, PGE had regulatory assets of $31 million earning a return on investment at the following rates: (i) $18 million at PGE's cost of debt of 6.065%; (ii) $10 million earning a return by inclusion in rate base; and (iii) $3 million at the approved rate for deferred accounts under amortization, ranging from 1.47% to 2.24%, depending on the year of approval.

Price risk management represents the difference between the net unrealized losses recognized on derivative instruments related to price risk management activities and their realization and subsequent recovery in customer prices. For further information regarding assets and liabilities from price risk management activities, see Note 5, Price Risk Management.

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in customer prices 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 customer prices 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 recovery in customer prices during the corresponding contract settlement month.

Deferred capital projects represents costs related to four capital projects that were deferred for future accounting treatment pursuant to the Company's last general rate case. The recovery of these project costs in future customer prices is subject to a regulated earnings test and approval by the OPUC.

Asset retirement obligations represent the difference in the timing of recognition of (i) the amounts recognized for depreciation expense of the asset retirement costs and accretion of the ARO, and (ii) the amount recovered in customer prices.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31,	
	2012	**2011**
Trojan decommissioning activities	$ 42	$ 37
Utility plant	39	38
Non-utility property	13	12
Asset retirement obligations	$ 94	$ 87

Trojan decommissioning activities represents the present value of future decommissioning expenditures for the plant, which ceased operation in 1993. The remaining decommissioning activities primarily consist of the long-term operation and decommissioning of the Independent Spent Fuel Storage Installation (ISFSI), an interim dry storage facility that is licensed by the Nuclear Regulatory Commission. The ISFSI is to house the spent nuclear fuel at the former plant site until an off-site storage facility is available. Decommissioning of the ISFSI and final site restoration activities will begin once shipment of all the spent fuel to a U.S. Department of Energy (USDOE) facility is complete.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp, collectively referred to as Plaintiffs) 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 were seeking approximately $112 million in damages incurred through 2009.

A trial before the U.S. Court of Federal Claims commenced in the fourth quarter of 2011 and concluded in early 2012. On November 30, 2012, the United States Court of Federal Claims issued a judgment awarding certain damages to the Plaintiffs. The judgment does not state the precise amount of the damages award, but directs the parties to consult and propose by the end of February 2013 a final amount for the Plaintiffs' recovery that is based on certain adjustments specified in the court's ruling. PGE estimates that the total amount of the award, as calculated pursuant to the judgment, will range from approximately $65 million to $75 million. Any award amount would be allocated among the Plaintiffs. The judgment includes damages incurred through 2009. The Plaintiffs may seek damages for subsequent years through a separate legal proceeding.

The USDOE will likely appeal, which will defer any damage payment indefinitely. The Trojan ARO will not be impacted by the outcome of this case as such potential recovery is for past decommissioning costs and the ARO reflects only future decommissioning expenditures. Any proceeds received related to this legal matter would flow to the benefit of customers to offset amounts previously collected from customers in relation to Trojan decommissioning activities.

Utility plant represents AROs that 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 was substantially completed at Bull Run in 2012.

During 2011, an updated decommissioning study for PGE's Boardman coal-fired plant was completed, which included the assumption that Boardman's coal-fired operations cease in 2020 rather than 2040. As a result of the study, PGE increased its ARO related to Boardman by approximately $20 million, with a corresponding increase in the cost basis of the plant, included in Electric utility plant, net on the balance sheets. Such transaction is non-cash and is excluded from investing activities in the statement cash flows for the year ended December 31, 2011.

Non-utility property primarily 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,	
	2012	**2011**
Balance as of beginning of year	$ 87	$ 64
Liabilities incurred	—	1
Liabilities settled	(3)	(4)
Accretion expense	6	4
Revisions in estimated cash flows	4	22
Balance as of end of year	$ 94	$ 87

Pursuant to regulation, the amortization of utility plant AROs is included in depreciation expense and in customer prices. 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 approximately $4 million annually, with an equal amount recorded in Depreciation and amortization expense.

PGE maintains a separate trust account, Nuclear decommissioning trust in the balance sheets, 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 facility 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 as management believes that these assets will be used in utility operations for the foreseeable future.

NOTE 8: REVOLVING CREDIT FACILITIES

PGE has two unsecured revolving credit facilities, with an aggregate borrowing capacity of $700 million, as follows:

- A $400 million syndicated credit facility, which is scheduled to terminate in November 2017; and
- A $300 million syndicated credit facility, which is scheduled to terminate in December 2016.

Pursuant to the terms of the agreements, both credit facilities may be used for general corporate purposes and as backup for commercial paper borrowings, and 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. Both credit facilities contain two, one-year extensions subject to approval by the banks, require annual fees based on PGE's unsecured credit ratings, and contain customary covenants and default provisions, including a requirement that limits indebtedness, as defined in the agreement, to 65.0% of total capitalization. As of December 31, 2012, PGE was in compliance with this covenant with a 48.9% 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 $700 million through February 6, 2014. 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, 2012, PGE had no borrowings under the credit facilities, with $17 million of commercial paper outstanding, which is classified as Short-term debt in the balance sheet, and $67 million of letters of credit issued. As of December 31, 2012, the aggregate unused available credit under the credit facilities was $616 million.

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

	Years Ended December 31,	
	2012	**2011**
Average daily amount of short-term debt outstanding	4	2
Weighted daily average interest rate *	0.4%	0.4%
Maximum amount outstanding during the year	44	44

* 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,	
	2012	**2011**
First Mortgage Bonds, rates range from 3.46% to 9.31%, with a weighted average rate of 5.84% in 2012 and 5.83% in 2011, due at various dates through 2040	$ 1,515	$ 1,615
Pollution Control Revenue Bonds, 5% rate, due 2033	142	142
Pollution Control Revenue Bonds owned by PGE	(21)	(21)
Unamortized debt discount	—	(1)
Total long-term debt	$ 1,636	$ 1,735

First Mortgage Bonds—In accordance with the terms of the debt agreement, PGE repaid during October 2012 the 5.6675% Series of First Mortgage Bonds in the amount of $100 million. The Indenture securing PGE’s outstanding First Mortgage Bonds constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property.

Pollution Control Revenue Bonds—PGE has the option to remarket $21 million of Pollution Control Revenue Bonds held by the Company through 2033. At the time of any remarketing, PGE can choose a new interest rate period that could be daily, weekly, or a fixed term. The new interest rate would be based on market conditions at the time of remarketing. The Pollution Control Revenue Bonds could be backed by first mortgage bonds or a bank letter of credit depending on market conditions.

As of December 31, 2012, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2013	$ 100
2014	—
2015	70
2016	67
2017	58
Thereafter	1,341
	$ 1,636

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. The plan has been closed to most new employees since January 31, 2009 and to all new employees since January 1, 2012, with no changes in benefits provided to existing participants.

The assets of the pension plan are held in a trust and are comprised of equity and debt instruments, as well as alternative asset investment vehicles, all of which are recorded at fair value. Pension plan calculations include several assumptions which are reviewed annually and are updated as appropriate, with the measurement date of December 31.

PGE made no contributions to the pension plan in 2012, and contributed $26 million in 2011. No contributions to the pension plan are expected in 2013.

Other Postretirement Benefits—PGE has non-contributory postretirement health and life insurance plans, as well as Health Reimbursement Accounts (HRAs) for its employees (collectively “Other Postretirement Benefits” in the following tables). Employees are covered under a Defined Dollar Medical Benefit Plan which limits PGE’s obligation pursuant to the postretirement health plan by establishing a maximum benefit per employee with employees paying the additional cost.

The assets of these plans are held in voluntary employees’ beneficiary association trusts and are comprised of 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. Postretirement health and life insurance benefit plan calculations include several assumptions which are reviewed annually with PGE’s consulting actuaries and trust investment consultants and updated as appropriate, with measurement dates of December 31.

Contributions to the HRAs provide for claims by retirees for qualified medical costs. For bargaining employees, the participants’ accounts are credited with 58% of the value of the employee’s accumulated sick time as of April 30, 2004, a stated amount per compensable hour worked, plus 100% of their earned time off accumulated at the time of retirement. For active non-bargaining employees, the Company grants a fixed dollar amount that will become available for qualified medical expenses upon their retirement.

Non-Qualified Benefit Plans—The Non-Qualified Benefit Plans (NQBP) in the following tables include obligations for a Supplemental Executive Retirement Plan, and a directors pension plan, both of which were closed to new participants in 1997. The NQBP also include pension make-up benefits for employees that participate in the unfunded Management Deferred Compensation Plan (MDCP). 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 two retired 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 a funding source for these plans.

Trust assets and plan liabilities related to the NQBP included in PGE's balance sheets are as follows as of December 31 (in millions):

	2012			2011		
	NQBP	**Other NQBP**	**Total**	**NQBP**	**Other NQBP**	**Total**
Non-qualified benefit plan trust	$ 15	$ 17	$ 32	$ 17	$ 19	$ 36
Non-qualified benefit plan liabilities *	27	77	102	27	76	101

See "*Trust Accounts*" in Note 3, Balance Sheet Components, for information on the Non-qualified benefit plan trust.

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. 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,			
	2012		2011	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	68%	67%	68%	67%
Debt securities	32	33	32	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	63%	72%	61%	72%
Debt securities	37	28	39	28
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	17%	17%	30%	23%
Debt securities	6	10	7	14
Insurance contracts	77	73	63	63
Total	100%	100%	100%	100%

* The Target for the Defined Benefit Plan represents the mid-point of the investment target range. 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, 2012			
	Level 1	Level 2	Level 3	Total
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 1	$ —	$ 1
Equity securities:				
Domestic	150	15	—	165
International	166	—	—	166
Debt securities:				
Domestic government and corporate credit	—	165	—	165
Corporate credit	8	—	—	8
Private equity funds	—	—	32	32
	$ 324	$ 181	$ 32	$ 537
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 8	$ —	$ 8
Equity securities:				
Domestic	8	1	—	9
International	8	—	—	8
Debt securities—Domestic government	3	—	—	3
	$ 19	$ 9	$ —	$ 28

	As of December 31, 2011			
	Level 1	Level 2	Level 3	Total
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 3	$ —	$ 3
Equity securities:				
Domestic	151	12	—	163
International	54	51	—	105
Debt securities:				
Domestic government and corporate credit	—	78	—	78
Corporate credit	76	—	—	76
Private equity funds	—	—	32	32
Alternative investments	—	—	30	30
	$ 281	$ 144	$ 62	$ 487
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 7	$ —	$ 7
Equity securities:				
Domestic	12	1	—	13
International	2	2	—	4
Debt securities—Domestic government	3	—	—	3
	$ 17	$ 10	$ —	$ 27

An overview of the identification of Level 1, 2, and 3 financial instruments is provided in Note 4, Fair Value of Financial Instruments. The following methods are used in valuation of each asset class of investments held in the pension and other postretirement benefit plan trusts.

Money market funds—PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short term treasury bills, federal agency securities, certificates of deposit, and commercial paper. Money market funds held in the trusts are classified as Level 2 instruments as they are traded in an active market of similar securities but are not directly valued using quoted prices.

Equity securities—Equity mutual fund and common stock securities are primarily classified as Level 1 securities based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and NYSE. Certain mutual fund assets included in commingled trusts or separately managed accounts are classified as Level 2 securities due to pricing inputs that are not directly or indirectly observable in the marketplace.

Debt securities—PGE invests in highly-liquid United States treasury and corporate credit mutual fund securities to support the investment objectives of the trusts. These securities are classified as Level 1 instruments due to the highly observable nature of pricing in an active market.

Fair values for Level 2 debt securities, including municipal debt and corporate credit securities, mortgage-backed securities and asset-backed securities are determined by evaluating pricing data, such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation if applicable.

Private equity funds—PGE invests in 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. Private equity investments are classified as Level 3 securities due to fund valuation methodologies that utilize discounted cash flow, market comparable and limited secondary market pricing to develop estimates of fund valuation. PGE valuation of individual fund performance compares stated fund performance against published benchmarks.

Alternative investments—Investments in a portable alpha strategy are comprised of long positions 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. Valuation of hedge funds included within this vehicle is provided by fund managers using unobservable internally modeled inputs. PGE performs validation procedures of manager performance by comparing stated performance against published benchmarks. Alternative investments are classified as Level 3 due to lack of observable market inputs and relative illiquidity of the fund.

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 three years ended December 31, 2012 (in millions):

	Private equity funds	Alternative investments	Total Level 3
Balance as of December 31, 2010	$ 23	$ 28	$ 51
Purchases	7	—	7
Realized loss on sales	(2)	—	(2)
Unrealized gain on assets	4	2	6
Balance as of December 31, 2011	32	30	62
Purchases and sales, net	(1)	(30)	(31)
Realized gain (loss) on sales	(1)	6	5
Unrealized gain (loss) on assets	2	(6)	(4)
Balance as of December 31, 2012	$ 32	$ —	$ 32

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, 2012 and 2011. Information related to the Other NQBP is not included in the following tables (dollar in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2012	2011	2012	2011	2012	2011
Benefit obligation:						
As of January 1	$ 634	$ 550	$ 75	$ 79	$ 27	$ 25
Service cost	14	12	2	2	—	—
Interest cost	31	29	3	4	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial loss (gain)	77	69	7	(5)	1	3
Contractual termination benefits	—	—	1	—	—	—
Benefit payments	(28)	(26)	(6)	(7)	(2)	(2)
As of December 31	$ 728	$ 634	$ 84	$ 75	$ 27	$ 27
Fair value of plan assets:						
As of January 1	$ 487	$ 473	$ 27	$ 16	$ 17	$ 19
Actual return on plan assets	78	14	3	—	—	—
Company contributions	—	26	2	16	—	—
Participants' contributions	—	—	2	2	—	—
Benefit payments	(28)	(26)	(6)	(7)	(2)	(2)
As of December 31	$ 537	$ 487	$ 28	$ 27	$ 15	$ 17
Unfunded position as of December 31	$ (191)	$ (147)	$ (56)	$ (48)	$ (12)	$ (10)
Accumulated benefit plan obligation as of December 31	$ 640	$ 566	N/A	N/A	$ 27	$ 27

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, 2012 and 2011. Information related to the Other NQBP is not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2012	**2011**	**2012**	**2011**	**2012**	**2011**
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ 40	$ 97	$ 5	$ (4)	$ 2	$ 2
Amortization of net actuarial loss	(17)	(8)	(1)	(1)	(1)	(1)
Amortization of prior service cost	—	(1)	(1)	(1)	—	—
	$ 23	$ 88	$ 3	$ (6)	$ 1	$ 1
Amounts included in AOCL*:						
Net actuarial loss	$ 298	$ 275	$ 18	$ 15	$ 11	$ 10
Prior service cost	1	1	4	4	—	—
	$ 299	$ 276	$ 22	$ 19	$ 11	$ 10
Assumptions used:						
Discount rate for benefit obligation	4.24%	5.00%	2.77% - 4.13%	3.76% - 4.90%	4.24%	5.00%
Discount rate for benefit cost	5.00%	5.47%	3.76% - 4.90%	4.02% - 5.40%	5.00%	5.47%
Weighted average rate of compensation increase for benefit obligation	3.65%	3.71%	4.58%	4.58%	N/A	N/A
Weighted average rate of compensation increase for benefit cost	3.71%	3.80%	4.58%	4.83%	N/A	N/A
Long-term rate of return on plan assets for benefit obligation	8.25%	8.25%	6.50%	7.09%	N/A	N/A
Long-term rate of return on plan assets for benefit cost	8.25%	8.50%	7.09%	6.44%	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	
	2012	**2011**	**2012**	**2011**	**2012**	**2011**
Service cost	$ 14	$ 12	$ 2	$ 2	$ —	$ —
Interest cost on benefit obligation	31	29	3	4	1	1
Expected return on plan assets	(41)	(42)	(1)	(1)	—	—
Amortization of prior service cost	—	1	1	1	—	—
Amortization of net actuarial loss	17	8	1	1	1	1
Net periodic benefit cost	$ 21	$ 8	$ 6	$ 7	$ 2	$ 2

PGE estimates that $27 million will be amortized from AOCL into net periodic benefit cost in 2013, consisting of a net actuarial loss of $24 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 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					
	2013	**2014**	**2015**	**2016**	**2017**	**2018 - 2022**
Defined benefit pension plan	$ 32	$ 33	$ 35	$ 37	$ 38	$ 215
Other postretirement benefits	5	5	5	5	5	26
Non-qualified benefit plans	2	2	2	2	2	10
Total	$ 39	$ 40	$ 42	$ 44	$ 45	$ 251

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 2012, 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2013, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019; and
- For 2011, 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2012 through 2013, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019.

A one percentage point increase or decrease in the above health care cost assumption would have no material impact on total service or interest cost, or on the postretirement benefit obligation.

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan that covers substantially all employees. For eligible employees who are covered by PGE's defined benefit pension plan, the Company matches employee contributions up to 6% of the employee's base pay. For eligible employees who are not covered by PGE's defined benefit pension plan, the Company contributes 5% of the employee's base salary, whether or not the employee contributes to the 401(k) Plan, and also matches employee contributions up to 5% of the employee's base pay.

For bargaining employees, who are subject to the International Brotherhood of Electrical Workers Local 125 agreements, the Company contributes 1% of the employee's base salary, whether or not the employee contributes to the 401(k) Plan.

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. PGE made contributions to employee accounts of $16 million in each of 2012 and 2011.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,	
	2012	**2011**
Current:		
Federal	$ 16	$ 2
State and local	1	—
	17	2
Deferred:		
Federal	30	43
State and local	17	13
	47	56
Income tax expense	$ 64	$ 58

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,	
	2012	**2011**
Federal statutory tax rate	35.0%	35.0%
Federal tax credits	(11.8)	(12.7)
State and local taxes, net of federal tax benefit	3.5	2.6
Adjustment to deferred taxes for change in blended composite state tax rate	2.6	—
Flow through depreciation and cost basis differences	2.4	2.1
Other	(0.6)	1.3
Effective tax rate	31.1%	28.3%

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

	As of December 31, 2012	As of December 31, 2011
Deferred income tax assets:		
Employee benefits	$ 163	$ 136
Price risk management	80	153
Tax credits, net of valuation allowance	55	56
Regulatory liabilities	21	14
Depreciation and amortization	9	18
Tax loss carryforwards	—	1
Other	12	10
Total deferred income tax assets	340	388
Deferred income tax liabilities:		
Depreciation and amortization	632	590
Regulatory assets	224	274
Price risk management	3	8
Employee benefits	1	1
Other	17	11
Total deferred income tax liabilities	877	884
Deferred income tax liability, net	$ (537)	$ (496)

PGE has federal and state tax credit carryforwards of $41 million and $14 million, respectively, which will expire at various dates from 2014 through 2031.

PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2012 and 2011 will be realized; accordingly, no valuation allowance has been recorded. During the year ended December 31, 2011, the valuation allowance decreased $2 million as a result of the expiration of unused state credits.

As of December 31, 2012 and 2011, PGE had no unrecognized tax benefits. 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. During the year ended December 31, 2010, the Company recognized $1 million in interest and no penalties. During 2011, the unrecognized tax benefit of $2 million was recognized 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) is in the process of finalizing an examination of PGE's income tax returns for 2006, 2009, and 2010, for which no material findings have been identified. The Company is not currently under examination by state or local tax authorities.

NOTE 12: STOCK PURCHASE PLANS

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP), under which a total of 625,000 shares of the Company's common stock 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 value on the purchase date) or 1,500 shares, whichever is less. There are two six-month offering periods each year, January 1 through June 30 and July 1 through December 31, during which eligible employees may purchase shares of PGE common stock at a price equal to 95% of the fair value of the stock on the purchase date, the last day of the offering period. As of December 31, 2012, there were 478,758 shares available for future issuance pursuant to the ESPP.

Dividend Reinvestment and Direct Stock Purchase Plan

On April 1, 2011, PGE's Dividend Reinvestment and Direct Stock Purchase Plan (DRIP) became effective, under which a total of 2,500,000 shares of the Company's common stock may be issued. Under the DRIP, investors may elect to buy shares of the Company's common stock or elect to reinvest cash dividends in additional shares of the Company's common stock. As of December 31, 2012, there were 2,490,267 shares available for future issuance pursuant to the DRIP.

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 3,824,141 shares remain available for future issuance as of December 31, 2012.

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; such goals include return on equity and regulated asset base growth measures. 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, the committee may disregard or offset the effect of extraordinary, unusual or non-recurring items in determining results relative to these goals. 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. DERs represent an amount equal to dividends paid to shareholders on a share of PGE's common stock and vest on the same schedule as the stock units. The DERs 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, 2010	465,428	17.88
Granted	152,657	23.84
Forfeited	(106,979)	22.35
Vested	(19,702)	23.34
Outstanding as of December 31, 2011	491,404	18.54
Granted	186,495	24.72
Forfeited	(22,947)	18.95
Vested	(214,390)	15.67
Outstanding as of December 31, 2012	440,562	22.54

The number of vested Restricted and Performance Stock Units presented above exceed the number of shares issued for the vesting of restricted and performance stock units on the statements of equity because, upon vesting, the Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. The total value of Restricted and Performance Stock Units vested during the years ended December 31, 2012 and 2011 was $3 million and $1 million, respectively. The weighted average fair value is measured based on the closing price of PGE common stock on the date of grant. PGE recorded $4 million of stock-based compensation expense for the years ended December 31, 2012 and 2011, respectively, which is included in Administrative and general expense in the statements of income. Such amounts differ from those 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 $1 million in 2012, and less than $1 million in 2011, which is not included in Administrative and general expenses in the statements of income.

As of December 31, 2012, unrecognized stock-based compensation expense was $4 million, of which approximately $3 million and $1 million is expected to be expensed in 2013 and 2014, respectively. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the vesting of 111.6% and 115.0% of awarded Performance Stock Units for 2012 and 2011, respectively, with an estimated 5% forfeiture rate. No stock-based compensation costs have been capitalized and the Plan had no material impact on cash flows for the years ended December 31, 2012 and 2011.

NOTE 14: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2012, PGE's future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2013	2014	2015	2016	2017	Thereafter	Total
Capital and other purchase commitments	$ 81	$ 10	$ 11	$ 9	$ 2	$ 72	$ 185
Purchased power and fuel:							
Electricity purchases	154	83	82	64	36	440	859
Capacity contracts	21	21	20	19	—	—	81
Public Utility Districts	8	8	8	7	5	25	61
Natural gas	55	26	21	12	10	6	130
Coal and transportation	22	9	—	—	—	—	31
Operating leases	9	9	9	10	11	186	234
Total	$ 350	$ 166	$ 151	$ 121	$ 64	$ 729	$ 1,581

Capital and other purchase commitments—Certain commitments have been made for capital and other purchases for 2013 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 2037, and power capacity contracts through 2016. As of December 31, 2012, PGE has power sale contracts with counterparties of approximately $7 million in 2013 and $2 million in 2014.

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 preceding table 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, 2012	PGE Share		Contract Expiration	PGE Cost, including Debt Service	
		Output	Capacity		2012	2011
			(in MW)			
Priest Rapids and Wanapum	$ 928	9.0%	181	2052	$ 14	$ 14
Wells	238	19.4	159	2018	10	10
Portland Hydro	9	100.0	36	2017	4	4

Under contracts with the public utility districts, PGE has acquired a percentage of the output (Allocation) of 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 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 related to Boardman, which expire at various dates through 2014.

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 (i) the corporate headquarters lease, which expires in 2018, but includes renewal period options through 2043, and (ii) the Port of St. Helens land lease, where PGE's Beaver and Port Westward generating plants operate, which expires in 2096. Rent expense was $10 million in 2012 and $9 million in 2011.

The future minimum operating lease payments presented is net of sublease income of: $3 million in 2013, 2014 and 2015; $2 million in 2016; and $1 million in 2017. Sublease income was $3 million in 2012 and 2011.

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 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 2013 is approximately $47 million. Management believes that circumstances that could result in such amount, or any lesser amount, being owed by the Company are remote. The P&T Agreements expire on December 31, 2013, and PGE's obligation to pay damages owed by the Lessee to the Purchaser under the lease will terminate.

PGE enters into financial agreements and power and natural gas 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 the Company's historical experience and the evaluation of the specific indemnities. As of December 31, 2012, 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 balance sheets with respect to these indemnities.

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, 2012, 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	$ 479	$ 308	$ 8
Colstrip	20.00	1986	507	328	3
Pelton/Round Butte	66.67	1958 / 1964	215	48	5
Total			$ 1,201	$ 684	$ 16

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

NOTE 16: CONTINGENCIES

PGE is subject to legal, regulatory, and environmental proceedings, investigations, and claims that arise from time to time in the ordinary course of its business. Contingencies are evaluated using the best information available at the time the financial statements are prepared. Legal costs incurred in connection with loss contingencies are expensed as incurred. The Company may seek regulatory recovery of certain costs that are incurred in connection with such matters, although there can be no assurance that such recovery would be granted.

Loss contingencies are accrued, and disclosed if material, 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 reasonable estimate of probable loss cannot be determined, a range of loss may be established, in which case the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate.

A loss contingency will also be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred if the estimate or range of potential loss is material. If a probable or reasonably possible loss cannot be reasonably estimated, then the Company (i) discloses an estimate of such loss or the range of such loss, if the Company is able to determine such an estimate, or (ii) discloses that an estimate cannot be made.

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.

The Company evaluates, on a quarterly basis, developments in such matters that could affect the amount of any accrual, as well as the likelihood of developments that would make a loss contingency both probable and reasonably estimable. The assessment as to whether a loss is probable or reasonably possible, and as to whether such loss or a range of such loss is estimable, often involves a series of complex judgments about future events. Management is often unable to estimate a reasonably possible loss, or a range of loss, particularly in cases in which (i) the damages sought are indeterminate or the basis for the damages claimed is not clear, (ii) the proceedings are in the early stages, (iii) discovery is not complete, (iv) the matters involve novel or unsettled legal theories, (v) there are significant facts in dispute, (vi) there are a large number of parties (including where it is uncertain how liability, if any, will be shared among multiple defendants), or (vii) there is a wide range of potential outcomes. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

Trojan Investment Recovery

Regulatory Proceedings. 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.

Numerous challenges and appeals 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. 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 entered into agreements to settle the litigation related to recovery of, and return on, its investment in Trojan. The settlement, which was approved by the OPUC, allowed PGE to remove from its balance sheet the remaining investment in Trojan as of September 30, 2000, along with several largely offsetting regulatory liabilities. After offsetting the investment in Trojan with these credits, the remaining Trojan regulatory asset balance of approximately $5 million (after tax) was expensed. As a result of the settlement, PGE's investment in Trojan was no longer included in prices charged to customers, either through a return of or a return on that investment. The Utility Reform Project (URP) did not participate in the settlement and filed a complaint with the OPUC challenging the settlement agreements. In 2002, the OPUC issued an order (2002 Order) denying all of the URP's challenges. In 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.

The OPUC then issued an order in 2008 (2008 Order) that required PGE to provide refunds, including interest from September 30, 2000, to customers who received service from the Company during the period from October 1, 2000 to September 30, 2001. The Company recorded a charge of $33.1 million in 2008 related to the refund and accrued additional interest expense on the liability until refunds to customers were completed in the first quarter of 2010. The URP and the plaintiffs in the class actions described below separately appealed the 2008 Order to the Oregon Court of Appeals. On February 6, 2013, the Oregon Court of Appeals issued an opinion that upheld the 2008 Order.

Class Actions. In two separate legal proceedings, lawsuits were filed in Marion County Circuit Court against PGE in 2003 on behalf of two classes of electric service customers. The class action lawsuits seek damages totaling $260 million, plus interest, as a result of the Company's inclusion, in prices charged to customers, of a return on its investment of Trojan.

In 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 can be offered to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment that the Company collected in prices.

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. The Marion County Circuit Court subsequently abated the class actions in response to the ruling of the Oregon Supreme Court.

As noted above, on February 6, 2013, the Oregon Court of Appeals issued an opinion that upheld the 2008 Order. Because the time periods in which to seek reconsideration or Oregon Supreme Court review of this decision have not yet lapsed and because the class actions described above remain pending, management believes that it is reasonably possible that the regulatory proceedings and class actions could result in a loss to the Company in excess of the amounts previously recorded and discussed above. However, because these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine PGE's potential liability, if any, or to estimate a range of potential loss.

Pacific Northwest Refund Proceeding

In 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 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 the 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 the evidence 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.

In October 2011, the FERC issued an Order on Remand, establishing an evidentiary hearing to determine whether any seller had engaged in unlawful market activity in the Pacific Northwest spot markets during the December 25, 2000 through June 20, 2001 period by violating specific contracts or tariffs, and, if so, whether a direct connection existed between the alleged unlawful conduct and the rate charged under the applicable contract. The FERC held that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome before a refund could be ordered. The FERC directed the presiding judge, if necessary, to determine a refund methodology and to calculate refunds, but held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Certain parties claiming refunds filed requests for rehearing of the Order on Remand, contesting, among other things, the applicable refund period reflected in the Order, the use of the *Mobile-Sierra* standard, any restraints in the Order on the type of evidence that could be introduced in the hearing, and the lack of market-wide remedy. The rehearing requests remain pending.

In December 2012, the FERC issued an order granting an interlocutory appeal of the trial judge’s ruling on the scope of the remand proceeding. In this order, the FERC held that its Order on Remand was not intended to alter the general state of the law regarding the *Mobile-Sierra* presumption. The FERC also held that the *Mobile-Sierra* presumption could be overcome either by (i) a showing that a respondent had violated a contract or tariff and that the violation had a direct connection to the rate charged under the applicable contract or (ii) a showing that the contract rate at issue imposed an excessive burden or seriously harmed the public interest.

In its October 2011 Order on Remand, the FERC held the hearing procedures in abeyance pending the results of settlement discussions, which it ordered be convened before a FERC settlement judge. Pursuant to the settlement proceedings, the Company received notice of two claims and reached agreements to settle both claims for an immaterial amount. The FERC approved both settlements during 2012.

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 (including CERS) as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 20, 2001, but did not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

The above-referenced settlements resulted in a release for the Company as a named respondent in the ongoing remand proceedings, which are limited to initial and direct claims for refunds, but there remains a possibility that additional claims related to this matter could be asserted against the Company in future proceedings if refunds are ordered against current respondents.

Management believes that this matter could result in a loss to the Company in excess of the settlement amounts referenced above. However, management cannot predict whether the FERC will order refunds in the Pacific Northwest Refund proceeding, which contracts would be subject to refunds, or how such refunds, if any, would be calculated. Due to these uncertainties, sufficient information is currently not available to determine PGE's liability, if any, or to estimate a range of reasonably possible loss.

EPA Investigation of Portland Harbor

A 1997 investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as the Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) 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. In January 2008, the EPA requested information from various parties, including PGE, concerning additional properties in or near the original segment of the river under investigation as well as several miles beyond. Subsequently, the EPA has listed additional PRPs, which now number over one hundred.

The Portland Harbor site is currently undergoing a remedial investigation (RI) and feasibility study (FS) pursuant to an Administrative Order on Consent (AOC) between the EPA and several PRPs known as the Lower Willamette Group (LWG), which does not include PGE.

In March 2012, the LWG submitted a draft FS to the EPA for review and approval. The draft FS, along with the RI, provide the framework for the EPA to determine a clean-up remedy for Portland Harbor that will be documented in a Record of Decision, which the EPA is expected to issue in 2015.

The draft FS evaluates several alternative clean-up approaches. These approaches would take from two to 28 years with costs ranging from $169 million to $1.8 billion, depending on the selected remedial action levels and the choice of remedy. The draft FS does not address responsibility for the costs of clean-up, allocate such costs among PRPs, or define precise boundaries for the clean-up. Responsibility for funding and implementing the EPA's selected clean-up will be determined after the issuance of the Record of Decision.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties discussed above, sufficient information is currently not available to determine PGE's liability for the cost of any required investigation or remediation of the Portland Harbor site or to estimate a range of potential loss.

DEQ Investigation of Downtown Reach

The Oregon Department of Environmental Quality (DEQ) has executed a memorandum of understanding with the EPA to administer and enforce clean-up activities for portions of the Willamette River that are upriver from the Portland Harbor Superfund site (the “Downtown Reach”). In January of 2010, the DEQ issued an order requiring PGE to perform an investigation of certain portions of the Downtown Reach. PGE completed this investigation in December 2011 and entered into a consent order with the DEQ in July 2012 to conduct a feasibility study of alternatives for remedial action for the portions of the Downtown Reach that were included within the scope of PGE’s investigation. It is expected that the feasibility study will be completed by the end of 2013.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, because the feasibility study continues, sufficient information is currently not available to determine PGE’s liability for the cost of any required investigation or remediation of the Downtown Reach site or to estimate a range of potential loss.

EPA Investigation of Harbor Oil

Harbor Oil, Inc. operated an oil reprocessing business on a site located in north Portland (Harbor Oil), until about 1999. Subsequently, other companies have continued to conduct operations on the site. Until 2003, PGE contracted with the operators of the site to provide used oil from the Company’s power plants and electrical distribution system to the operators for use in their reprocessing business. Other entities continue to utilize Harbor Oil for the reprocessing of used oil and other lubricants.

In 2003, the EPA included the Harbor Oil site on the National Priority List as a federal Superfund site. PGE received a Notice from the EPA in 2005, in which the Company was named as one of fourteen PRPs with respect to Harbor Oil. Subsequently, an AOC was signed by the EPA and six other parties, including PGE, to implement an RI/FS at Harbor Oil. In 2011, the final draft of the RI report was submitted to the EPA.

In March 2012, the EPA approved the RI and stated that it intends to recommend no action on the site, based on the conclusions of the risk assessment conducted under the CERCLA. Following a public notice and comment period, the EPA is expected to issue a final Record of Decision in March 2013.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, sufficient information is currently not available to determine PGE’s liability for the cost of any remediation of the Harbor Oil site or to estimate a range of potential loss.

Alleged Violation of Environmental Regulations at Colstrip

On July 30, 2012, PGE received a Notice of Intent to Sue for violations of the Clean Air Act (CAA) at Colstrip Steam Electric Station (Notice) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other Colstrip co-owners, including PPL Montana, LLC - the operator of Colstrip. PGE has a 20% ownership interest in Units 3 and 4 of Colstrip. The Notice alleges certain violations of the CAA, including New Source Review, Title V, and opacity requirements, and states that the Sierra Club and MEIC will: i) request a United States District Court to impose injunctive relief and civil penalties; ii) require a beneficial environmental project in the areas affected by the alleged air pollution; and iii) seek reimbursement of Sierra Club’s and MEIC’s costs of litigation and attorney’s fees.

Since July 2012, the Sierra Club and MEIC have amended their Notice three times. The first amendment, contained in a letter dated August 30, 2012, asserts that the Colstrip owners violated the Title V air quality operating permit during portions of 2008 and 2009. The second amendment, contained in a letter dated September 27, 2012, asserts that the owners have violated the CAA by failing to timely submit a complete air quality operating permit application to the Montana Department of Environmental Quality (MDEQ). The third amendment, received in December 2012, does not materially alter the prior assertions. Due to the uncertainties concerning this matter, PGE cannot predict the outcome or determine whether it is reasonably possible that the claims, if asserted, would have a material impact on the Company.

Challenge to AOC Related to Colstrip Wastewater Facilities

In August 2012, the operator of Colstrip entered into an AOC with the MDEQ, which established a comprehensive process to investigate and remediate groundwater seepage impacts related to the wastewater facilities at Colstrip. Within five years, under this AOC, the operator of Colstrip is required to provide financial assurance to MDEQ for the costs associated with closure of the waste water treatment facilities. This will establish an obligation for asset retirement, but the operator of Colstrip is unable at this time to estimate these costs, which will require both public and agency review.

In September 2012, Earthjustice filed an affidavit pursuant to Montana’s Major Facility Siting Act (MFSA) that sought review of the AOC by Montana’s Board of Environmental Review (BER), on behalf of environmental groups Sierra Club, the MEIC, and the National Wildlife Federation. In September 2012, the operator of Colstrip filed an election with the BER to have this proceeding conducted in Montana state district court as contemplated by the MFSA. In October 2012, Earthjustice, on behalf of Sierra Club, the MEIC and the National Wildlife Federation, filed with the Montana state district court a petition for a writ of mandamus and a complaint for declaratory relief alleging that the AOC fails to require the necessary actions under the MFSA and the Montana Water Quality Act with respect to groundwater seepage from the wastewater facilities at Colstrip. PGE cannot at this time predict the outcome of this matter or determine whether it is reasonably possible that it would have a material impact on the Company.

Revenue Bonds

In 2008, PGE repurchased $5.8 million of Pollution Control Revenue Bonds Series 1996 (Bonds) issued through the Port of Morrow, Oregon. In connection with the repurchase, PGE paid the $5.8 million repurchase price to Lehman Brothers Inc. (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. PGE subsequently filed a claim for return of the Bonds from Lehman. In November 2009, the trustee appointed to liquidate the assets of Lehman (Trustee) allowed PGE’s claim as a net equity claim for securities.

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.

Oregon Tax Court Ruling

On September 17, 2012, the Oregon Tax Court issued a ruling contrary to an Oregon Department of Revenue interpretation and a current Oregon administrative rule, regarding the treatment of wholesale electricity sales. The underlying issue is whether electricity should be treated as tangible or intangible property for state income tax apportionment purposes. The Oregon Department of Revenue has appealed the ruling of the Oregon Tax Court to the Oregon Supreme Court. It is uncertain whether the ruling would apply retroactively to all open tax years, which, for PGE, include 2006 through 2012.

If the ruling is upheld, PGE estimates that its income tax liability could increase by as much as $12 million due to the impact of the increased assessment of prior years' liability and an increase in the tax rate at which deferred tax liabilities would be recognized in future years. Due to the uncertainty concerning the resolution of this matter, PGE cannot predict the outcome. The Company may seek regulatory recovery of any incremental tax, although there can be no assurance that such recovery would be granted.

Other Matters

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

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(5,407,651)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(738,690)
3	Preceding Quarter/Year to Date Changes in Fair Value				68,160
4	Total (lines 2 and 3)				(670,530)
5	Balance of Account 219 at End of Preceding Quarter/Year				(6,078,181)
6	Balance of Account 219 at Beginning of Current Year				(6,078,181)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(297,809)
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				(297,809)
10	Balance of Account 219 at End of Current Quarter/Year				(6,375,990)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	67,352		(5,340,299)		
2	(68,160)		(806,850)		
3			68,160		
4	(68,160)		(738,690)	146,844,382	146,105,692
5	(808)		(6,078,989)		
6	(808)		(6,078,989)		
7			(297,809)		
8					
9			(297,809)	141,315,881	141,018,072
10	(808)		(6,376,798)		

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

Comprised of the net amount of the actuarial valuation of $1,250,966 of non-qualified benefit plans net of taxes of $(512,276).

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

PGE records a regulatory asset or regulatory liability pursuant to ASC 980 to offset the effects of unrealized gains and losses from the changes in the fair value of the Price Risk Management Assets and Liabilities designated as cash flow hedges. Consists of ASC 815 Unrealized Mark-to-Market loss of $(112,662) on natural gas forward and swap contracts and Deferred Taxes of $44,502.

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

Comprised of the net amount of the actuarial valuation of $580,081 of non-qualified benefit plans net of taxes of $(282,272).

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. No activity in 2012.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	6,800,035,495	6,800,035,495
4	Property Under Capital Leases		
5	Plant Purchased or Sold	-232,078	-232,078
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	6,799,803,417	6,799,803,417
9	Leased to Others		
10	Held for Future Use	6,331,947	6,331,947
11	Construction Work in Progress	140,303,251	140,303,251
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	6,946,438,615	6,946,438,615
14	Accum Prov for Depr, Amort, & Depl	3,250,583,440	3,250,583,440
15	Net Utility Plant (13 less 14)	3,695,855,175	3,695,855,175
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,099,402,013	3,099,402,013
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	151,181,427	151,181,427
22	Total In Service (18 thru 21)	3,250,583,440	3,250,583,440
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)	3,250,583,440	3,250,583,440

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
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					17
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					19
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					30
					31
					32
					33

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

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

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

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year: Amortization (d)	Changes during Year: Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
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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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	140,637,900	3,593,776
4	(303) Miscellaneous Intangible Plant	190,736,851	45,220,217
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	331,374,751	48,813,993
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,160,761	-90
9	(311) Structures and Improvements	216,014,905	2,457,164
10	(312) Boiler Plant Equipment	442,983,772	14,091,475
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	166,011,079	1,408,794
13	(315) Accessory Electric Equipment	47,139,706	18,580
14	(316) Misc. Power Plant Equipment	12,148,652	770
15	(317) Asset Retirement Costs for Steam Production	24,903,797	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	913,362,672	17,976,693
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	38,133,362	9,801,646
29	(332) Reservoirs, Dams, and Waterways	233,459,352	22,660,086
30	(333) Water Wheels, Turbines, and Generators	46,829,674	5,813,259
31	(334) Accessory Electric Equipment	16,030,282	491,826
32	(335) Misc. Power PLant Equipment	1,851,361	2,053
33	(336) Roads, Railroads, and Bridges	9,412,238	350,083
34	(337) Asset Retirement Costs for Hydraulic Production	4,276	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	351,768,171	39,118,953
36	D. Other Production Plant		
37	(340) Land and Land Rights	48,946	
38	(341) Structures and Improvements	114,543,970	1,443,554
39	(342) Fuel Holders, Products, and Accessories	115,234,239	651,938
40	(343) Prime Movers		
41	(344) Generators	1,280,031,737	1,989,758
42	(345) Accessory Electric Equipment	62,509,438	3,060,542
43	(346) Misc. Power Plant Equipment	9,101,291	1,067,203
44	(347) Asset Retirement Costs for Other Production	2,213,948	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,583,683,569	8,212,995
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,848,814,412	65,308,641

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	11,120,109	109,999
49	(352) Structures and Improvements	16,365,764	1,043,493
50	(353) Station Equipment	219,025,075	15,416,966
51	(354) Towers and Fixtures	46,806,048	2,244
52	(355) Poles and Fixtures	18,818,400	1,670,787
53	(356) Overhead Conductors and Devices	79,883,775	1,382,678
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)	392,358,542	19,626,167
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	13,681,528	15,101
61	(361) Structures and Improvements	35,868,982	1,032,357
62	(362) Station Equipment	355,526,111	30,401,264
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	308,051,860	18,363,250
65	(365) Overhead Conductors and Devices	513,087,674	20,736,935
66	(366) Underground Conduit	15,611,337	
67	(367) Underground Conductors and Devices	606,754,779	18,622,233
68	(368) Line Transformers	293,658,562	13,771,835
69	(369) Services	367,658,209	10,515,412
70	(370) Meters	122,948,704	3,295,226
71	(371) Installations on Customer Premises	376,133	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	57,026,531	1,615,767
74	(374) Asset Retirement Costs for Distribution Plant	460,131	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,690,710,541	118,369,380
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	6,091,707	1,105,319
87	(390) Structures and Improvements	67,276,848	4,804,844
88	(391) Office Furniture and Equipment	60,829,772	13,928,445
89	(392) Transportation Equipment	40,760,492	1,595,672
90	(393) Stores Equipment	2,503,117	348,569
91	(394) Tools, Shop and Garage Equipment	10,637,455	1,613,407
92	(395) Laboratory Equipment	10,514,460	134,748
93	(396) Power Operated Equipment	43,814,210	2,730,987
94	(397) Communication Equipment	71,607,533	1,269,101
95	(398) Miscellaneous Equipment	131,612	2,427
96	SUBTOTAL (Enter Total of lines 86 thru 95)	314,167,206	27,533,519
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)	314,231,694	27,533,519
100	TOTAL (Accounts 101 and 106)	6,577,489,940	279,651,700
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)	6,577,489,940	279,651,700

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
			144,231,676		3
23,010,430			212,946,638		4
23,010,430			357,178,314		5
					6
					7
			4,160,671		8
248			218,471,821		9
3,118,403			453,956,844		10
					11
1,918,916			165,500,957		12
19,132			47,139,154		13
			12,149,422		14
			24,903,797		15
5,056,699			926,282,666		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			6,047,626		27
11,413			47,923,595		28
118,826		-51,781	255,948,831		29
700,568			51,942,365		30
123,643		164,789	16,563,254		31
			1,853,414		32
704		1,342	9,762,959		33
			4,276		34
955,154		114,350	390,046,320		35
					36
			48,946		37
36,824		-8,036	115,942,664		38
36,078			115,850,099		39
					40
13,910,800			1,268,110,695		41
9,634			65,560,346		42
1,661			10,166,833		43
			2,213,948		44
13,994,997		-8,036	1,577,893,531		45
20,006,850		106,314	2,894,222,517		46

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

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
			11,230,108		48
2,187			17,407,070		49
270,956		7,148,007	241,319,092		50
			46,808,292		51
28,831			20,460,356		52
		-7,136,504	74,129,949		53
					54
					55
			286,332		56
			53,039		57
301,974		11,503	411,694,238		58
					59
1,115		6,663,411	20,358,925		60
79,152			36,822,187		61
1,278,446		-124,359	384,524,570		62
					63
1,212,151		1,266	325,204,225		64
870,355		104,897	533,059,151		65
87,751			15,523,586		66
553,675		-2,668	624,820,669		67
803,452		-78,367	306,548,578		68
156,304		-15,797	378,001,520		69
523,656		-1,447	125,718,827		70
			376,133		71
					72
321,370			58,320,928		73
			460,131		74
5,887,427		6,546,936	2,809,739,430		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
1,145			7,195,881		86
1,080,315		-78,185	70,923,192		87
8,108,788			66,649,429		88
1,450,836			40,905,328		89
			2,851,686		90
1,115,651		-10,452	11,124,759		91
699,392			9,949,816		92
1,744,901			44,800,296		93
268,346		-1,342	72,606,946		94
4,864			129,175		95
14,474,238		-89,979	327,136,508		96
					97
			64,488		98
14,474,238		-89,979	327,200,996		99
63,680,919		6,574,774	6,800,035,495		100
					101
		232,078	232,078		102
					103
63,680,919		6,342,696	6,799,803,417		104

Schedule Page: 204 Line No.: 102 Column: f

PGE has filed proposed journal entries with FERC through Docket AC12-135 to clear the account 102 balance. The balance in this account represents the sale of a 1.75 MW Solar facility in January 2012 between PGE and Bank of America Leasing & Capital LLC (BALC). PGE received regulatory approval for the sale from the Oregon Public Utility Commission in January 2012 through OPUC Order 12-006.

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Future	543,591
3	Sewell, Washington County, OR	2008	2017	2,609,767
4	Cornell, Washington County, OR	2007	2013	649,143
5	Shute Road, Washington County, OR	2009	2013	1,721,229
6	Highway 26 Easements, Washington County, OR	2009	2013	278,500
7	Sewell Easement, Washington County, OR	2009	2017	334,927
8	Other Land and Land Rights (8 in Number)	Various	Various	194,790
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
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46				
47	Total			6,331,947

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Cascade Crossing Transmission Project	46,387,356
2	Advanced Metering Infrastructure - Remote Frequency Upgrade	8,211,170
3	IT Cyber Security Improvements	8,041,730
4	Boardman - Emissions Controls	6,432,306
5	North Fork - Install Fish Sorting Facility	5,526,795
6	Pelton/Round Butte - Fish Passage Improvements	5,379,058
7	Time And Attendance - Software Purchase And Implementation	4,586,413
8	North Fork - Improve Fish Passage	4,001,343
9	Carver Backup Facility - New Site Construction	3,738,915
10	Colstrip - Capital Projects	3,113,396
11	Wallace Substation - Increase Site Capacity	2,809,100
12	Avery Facility - Site Upgrades and Remodel	2,640,854
13	Substation Fitness - Replace Obsolete Relays	2,567,897
14	PGE Website - Add Customer Use Features	2,484,661
15	Bell Substation - Increase Site Capacity	2,296,558
16	Dispatchable Generation Projects	2,132,179
17	Customer Information System - Software Purchase and Implementation	2,125,907
18	Salem Smart Feeder Project	2,113,395
19	River District Install Vaults and Conduit	1,778,050
20	Sunset Substation - Increase Site Capacity	1,585,187
21	Pelton/Round Butte - Licensing Requirements	1,559,799
22	Power Scheduling Accounting System - Software Purchase and Implementation	1,436,257
23	Tri-Met Bridge 115-Kv Line Construction	1,149,000
24	Voice System Replacement Project	1,087,718
25	System Dispatch Control - Replace Communications System	1,046,594
26	Sand Springs Capacitor Station - Replace Station Controls	1,005,895
27	Clackamas River Habitat Enhancements	898,451
28	Boardman - New Fire Detection System	891,122
29	Boardman - Upgrade Fire Protection System	887,441
30	Oak Grove - Install Minimal Flow Release Structure	884,810
31	Rivermill - Fish Passage Improvements	801,858
32	MyPGE Employee Portal - Software Purchase and Implementation	726,182
33	Rosemont Switching Station - Increase Site Capacity	680,827
34	Fort Rock Capacitor Station - Replace Station Controls	671,011
35	Construct New Distribution Substation - Cornell	657,721
36	Clackamas River - Licensing Requirements	568,181
37	IBM Enterprise Content Management - Software Purchase and Implementation	563,486
38	Marquam Property - Site Preparation	518,896
39	Substation Arc Flash Safety Upgrades	513,215
40	Pelton/Round Butte - Generator Unit 3 Rewind	490,891
41	Oak Grove - Replace Outdoor Bar Racks	447,054
42	Energy Management System - Software Purchase and Implementation	414,499
43	TOTAL	140,303,251

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Pelton/Round Butte - Shoreline Erosion Controls	410,224
2	Faraday - Diversion Dam Rack Cleaner	386,319
3	Safety Management System - Software Purchase and Implementation	368,585
4	Fleet Management - Install Automated Vehicle Locating	368,464
5	Communication System Improvements - Install Fiber Optic Cable	360,848
6	Clackamas River Aquatic Enhancements	356,616
7	Boardman - Replace Variable Speed Drive's on ID Fans	343,727
8	Oracle Enterprise Management - Software Licensing and Additional Features	303,392
9	Energy Tracker - Software Purchase and Implementation	296,304
10	Oracle Business Intelligence Enterprise - Software Purchase and Implementation	291,572
11		
12	Minor Project Balance < 1,000,000	964,022
13		
14		
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42		
43	TOTAL	140,303,251

Schedule Page: 216 Line No.: 4 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.: 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.: 10 Column: a

Related to Colstrip Units 3 & 4 which are jointly owned with Northwestern Energy LLC, PP&L Montana, LLC, Puget Sound Energy, Inc., PacificCorp, and Avista Corporation. Respondent's 20% share of jointly owned costs is reported.

Schedule Page: 216 Line No.: 21 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.: 28 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.: 29 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.: 40 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.: 1 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.: 7 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	2,914,574,306	2,914,574,306		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	222,779,529	222,779,529		
4	(403.1) Depreciation Expense for Asset Retirement Costs	2,906,607	2,906,607		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,821,871	3,821,871		
7	Other Clearing Accounts	261,352	261,352		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	229,769,359	229,769,359		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	40,668,228	40,668,228		
13	Cost of Removal	5,211,001	5,211,001		
14	Salvage (Credit)	1,168,790	1,168,790		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	44,710,439	44,710,439		
16	Other Debit or Cr. Items (Describe, details in footnote):	-231,213	-231,213		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,099,402,013	3,099,402,013		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	629,951,608	629,951,608		
21	Nuclear Production				
22	Hydraulic Production-Conventional	145,086,093	145,086,093		
23	Hydraulic Production-Pumped Storage				
24	Other Production	413,861,096	413,861,096		
25	Transmission	179,002,151	179,002,151		
26	Distribution	1,585,049,949	1,585,049,949		
27	Regional Transmission and Market Operation				
28	General	146,451,116	146,451,116		
29	TOTAL (Enter Total of lines 20 thru 28)	3,099,402,013	3,099,402,013		

Schedule Page: 219 Line No.: 7 Column: c

Boardman rail car depreciation expense recorded into FERC 151 - Fuel Inventory.

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

PGE sold a 1.75 MW Solar facility in January 2012 to Banc of America Leasing & Capital LLC (BALC). PGE received regulatory approval for the sale from the Oregon Public Utility Commission in January 2012 through OPUC Order 12-006. Amounts related to the solar facility were reclassified to FERC 102 Electric Plant Sold. PGE has filed proposed journal entries with the FERC through Docket AC 12-135 to clear the Account 102 balance.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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			87,992
4	Sub - TOTAL			88,992
5				
6	Salmon Springs Hospitality Group			
7	Common Stock	04/09/98		10,000
8	Equity in Earnings			23,338
9	Sub - TOTAL			33,338
10				
11	SunWay 1, LLC			
12	Paid in Capital	5/29/08		156,273
13	Equity in Earnings			-109,978
14	Sub - TOTAL			46,295
15				
16	SunWay 2, LLC			
17	Paid in Capital	9/16/08		525,014
18	Equity in Earnings			-215,930
19	Sub - TOTAL			309,084
20				
21	SunWay 3, LLC			
22	Paid in Capital	10/19/09		2,415,395
23	Equity in Earnings			-825
24	Sub - TOTAL			2,414,570
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
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42	Total Cost of Account 123.1 $ 3,722,671		TOTAL	2,892,279

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
88,133		176,125		3
88,133		177,125		4
				5
				6
		10,000		7
391,400	-400,000	14,738		8
391,400	-400,000	24,738		9
				10
				11
		156,273		12
-3		-109,981		13
-3		46,292		14
				15
				16
	751,000	1,276,014		17
-105		-216,035		18
-105	751,000	1,059,979		19
				20
				21
		2,415,395		22
-33		-858		23
-33		2,414,537		24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
479,392	351,000	3,722,671		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 12/31/2012 (100%)</u>

In-Service Production cost: $1,097,814
Total installed capacity: 104 kW
Operations and Maintenance for 2012: $67,653

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

Represents PGE's share of SunWay2, 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 12/31/2012 (100%)</u>

In-service Production cost: $5,922,280
Total installed capacity: 1.1 MW
Operations and Maintenance for 2012: $1,323,594

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 12/31/2012 (100%)</u>

In-service Production cost: $7,454,015
Total installed cappacity: 2.4 MW
Operations and Maintenance for 2012: $643,061

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	33,794,768	39,663,607	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)	13,216,761	12,548,768	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	17,595,441	18,899,066	Generation
8	Transmission Plant (Estimated)	48,017	208,875	Transmission
9	Distribution Plant (Estimated)	1,367,910	1,345,935	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	434,061	165,157	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	32,662,190	33,167,801	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	6,081		Customer Service
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	4,659,816	4,817,251	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	71,122,855	77,648,659	

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

Balance primarily relates to costs associated with purchased renewable energy certificates (green tags).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	2013 No. (d)	2013 Amt. (e)
1	Balance-Beginning of Year	28,332.00	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	8,497.00	107,712		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	19,835.00	252,288	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	1,153.06		144.78	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	144.78			
40	Balance-End of Year	1,008.28		144.78	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		97		
45	Gains		97		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2014		2015		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
10,033.00		10,030.00		151,783.00		210,207.00	360,000	1
								2
								3
				14,522.00		14,522.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						8,497.00	107,712	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
10,033.00		10,030.00		166,305.00		216,232.00	252,288	29
								30
								31
								32
								33
								34
								35
144.78		144.78		4,198.48		5,785.88		36
				418.00		418.00		37
								38
				144.78		289.56		39
144.78		144.78		4,471.70		5,914.32		40
								41
								42
								43
					19		116	44
					19		116	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	2013 No. (d)	2013 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2014		2015		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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;	304,237,279	5,915,762	407	3,500,000	3,402,786
24	PGE has the authority to continue					
25	the recovery of the expense in					
26	rates, until decommissioning is					
27	complete, as authorized by OPUC					
28	(Order #07-0158, 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	304,237,279	5,915,762		3,500,000	3,402,786

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	LGIP #C0050-4884 FAC	8,722	561.7		
23	LGIP #3-336 SIS (G0438)	5,038	561.7	5,038	456
24	LGIP #0-25836 SIS	1,486	561.7	1,486	456
25	LGIP #3-136 SIS	691	561.7	691	456
26	LGIP #10-037 SIS	75	561.7	75	456
27	LGIP #11-041 FEA	5,107	561.7	5,107	456
28	LGIP #11-041 FAC	105	561.7	105	456
29	LGIP #11-042 SIS	5,221	561.7	5,221	456
30	LGIP #11-045 FAC	52,576	561.7	52,576	456
31	LGIP #11-045 FEA	3,131	561.7	3,131	456
32	LGIP #11-045 SIS	27,936	561.7	27,936	456
33	LGIP #11-046 APP	9,822	561.7	9,822	456
34	LGIP #11-046 FAC	47,199	561.7	47,199	456
35	LGIP #11-046 FEA	15,391	561.7	15,391	456
36	LGIP #11-046 SIS	7,154	561.7	7,154	456
37	LGIP #12-050 APP	6,117	561.7	6,117	456
38	LGIP #12-050 FAC	136	561.7	136	456
39	LGIP #12-050 SIS	5,066	561.7	5,066	456
40	LGIP #12-051 APP	5,235	561.7	5,235	456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	LGIP #12-051 FEA	9,077	561.7	9,077	456
23	LGIP #12-053 FEA	9,814	561.7	9,814	456
24	Other	(28)	561.7		
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231.1 Line No.: 24 Column: b

Represents various minor prior period adjustments to study costs credited 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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Tax Benefits Related to Book/Tax Basis Differences	55,071,199	1,741,175	282	6,249,367	50,563,007
2	Previously Flowed to Customers	35,955,578	1,389,978	283	3,636,885	33,708,671
3	(Amort. period is based on the lives of the					
4	properties, approximately 25 years.)					
5						
6	Photovoltaic Volumetric Incentive Pilot	1,694,409	3,176,000	407.3	4,808,006	62,403
7	(per OPUC Order No. 10-198 dtd 5/28/2010;					
8	amortization per Advice No. 11-30 dtd 12/2/2011;					
9	amortization period: 1/1/2012 - 12/31/2012)					
10						
11	Colstrip Common Facilities (28 year amort. ending	1,718,087		407.3	322,140	1,395,947
12	2017, FERC OCA-AD ltr dtd 5/23/1989)					
13						
14	Price Risk Management	365,226,395	68,513,725	various	240,104,008	193,636,112
15						
16	Deferred Broker Settlement	11,087,154	31,176,468	555	22,039,071	20,224,551
17						
18	Intervenor Funding (original deferral per OPUC	184,050	140,647	407.3	57,840	266,857
19	Order No. 03-388 dtd 7/2/2003; current year					
20	reauthorization through various orders; 2011					
21	amortization per Advice 10-22A dtd 12/23/2010)					
22						
23	Senate Bill 408 Deferral - Local Residual 2007	161,803	249	449.1/229	162,052	
24	Multnomah County Business Income Tax Balancing					
25						
26	Independent Evaluator Deferral	310,052	25,844			335,896
27	(per OPUC Order No. 08-010 dtd 1/14/2008)					
28						
29	Independent Evaluator Deferral (2011)	140,487	(6,998)			133,489
30	(per OPUC Order No. 11-154 dtd 5/10/2011)					
31						
32	Schedule 110 Energy Efficiency - Balancing Acct	13,009	259,808	407.3/431	272,817	
33	(per Advice No. 07/25 dtd 05/20/2008)					
34						
35	Automated Demand Response Balancing	50,378	19,133	908	69,511	
36	(per Advice 10-29 dtd 12/29/2010)					
37						
38	Smart Meter Project Office Costs	1,389,977	14,319	407.3	1,360,588	43,708
39	(per OPUC Order No. 08-209 dtd 4/11/2008;					
40	amortization per Advice No. 11-32 dated 12/12/2011;					
41	amortization period: 1/1/2012 - 12/31/2012)					
42						
43	Generation Plant Maintenance Deferral	4,791,444		557	684,492	4,106,952
44	TOTAL	784,667,938	170,848,570		309,589,687	645,926,821

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	(per OPUC Order no. 08-601 dtd 12/29/2008;					
2	amortization period: 1/1/2009 - 12/31/2018)					
3						
4	Stable Rate Revenue Balancing Acct	640,657	100,057			740,714
5	(per Advice No 06-13 dtd 6/22/2006)					
6						
7	Small Nonres Sch 123 SNA Deferral-2010	1,193,308	42,680	456	1,235,988	
8	Residential Sch 123 SNA Deferral-2010	2,382,470	85,211	456	2,467,681	
9	Residential Sch 123 SNA Deferral-2011	906,737	9,661	456	707,088	209,310
10	(reauthorized OPUC Order No. 11-110 dtd 4/7/2011)					
11						
12	Residential Sch 123 SNA Deferral-2012		2,274,987			2,274,987
13	(reauthorized OPUC Order No. 12-061 dtd 2/28/2012)					
14						
15	Trojan Refund Deferral - Incremental Costs	3,033,238	31,169	903	2,976,908	87,499
16	(per OPUC Order No. 09-133 dtd 4/14/2009;					
17	amortization per Advice No. 11-35 dated 12/22/2011;					
18	amortization period: 1/1/2012 - 12/31/2012)					
19						
20	SunWay Deferral	(1,370)	12,511	456/431	11,141	
21	(per OPUC Order No. 10-391 dtd 10/11/2010;					
22	amortization period: 01/01/2011 - 12/31/2011)					
23						
24	Residual Deferred Account	935,381	10,088	Various	857,530	87,939
25	(per OPUC Order No. 10-279 dtd 7/23/2010;					
26	amortization per Advice No. 11-32 dated 12/12/2011;					
27	amortization period: 1/1/2012 - 12/31/2012)					
28						
29	City of Glendale Wholesale Sales	1,200,000		447	1,200,000	
30	(FERC Docket No. ER10-1286-000)					
31						
32	Glass Insulator Deferral	554,590	771,818	571	15,359	1,311,049
33	(per OPUC Order No. 10-478 dtd 12/17/2010;					
34	UE 215 First Revenue Requirement Stipulation)					
35						
36	Pension Funding	275,507,249	40,194,305	926	16,988,364	298,713,190
37	Postretirement Funding	19,306,475	4,471,575	219/926	1,902,266	21,875,784
38	(per SFAS No. 158 adopted 12/31/2006;					
39	OPUC Order No. 07-051 dtd 2/12/2007)					
40						
41	Direct Access Open Enrollment Deferral - 2008	13,324	15,880	447	29,204	
42	(per Advice No. 10-22A dtd 12/28/2010					
43	amortization period: 1/1/2011 - 12/31/2011)					
44	TOTAL	784,667,938	170,848,570		309,589,687	645,926,821

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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						
2	ISFSI Pollution Control Tax Credit Deferral	274,000	5,051	254	284,150	-5,099
3	(per OPUC Order No. 01-777 dtd 8/31/2001)					
4						
5	Boardman Decommissioning Balancing	214,909	371,354	456	221,174	365,089
6	(per Advice No. 11-07 dtd 05/27/11)					
7						
8	Biglow Canyon Phase 2 Deferral	(89,258)	114,920	456	25,662	
9	(per OPUC Order No. 09-398 dtd 10/05/2009 &					
10	OPUC Order No. 10-391 dtd 10/11/2010;					
11	amortization period: 01/01/2010 - 12/31/2011)					
12						
13	Biglow Canyon Phase 3 Deferral	802,206	9,083	456	900,395	-89,106
14	(per OPUC Order No. 10-391 dtd 10/11/2010;					
15	amortization period: 1/1/2011 - 12/31/2012)					
16						
17	UE 215 Four Capital Projects Deferral		15,527,194			15,527,194
18	(per OPUC Order No. 10-478 dtd 12/17/2010,					
19	UE 215 Second Revenue Requirement Stipulation)					
20						
21	Baldock Revenue Requirement Deferral		350,678			350,678
22	(per OPUC Order No. 12-063 dtd 2/28/2012)					
23						
24						
25						
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32						
33						
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40						
41						
42						
43						
44	TOTAL	784,667,938	170,848,570		309,589,687	645,926,821

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

Amounts charged to Accounts 555,547, and 219.

Schedule Page: 232 Line No.: 18 Column: c

Current year reauthorization approved through OPUC Orders:
11-478, dated 12/01/2011, Intervenor matching Fund Grant
12-009, dated 01/13/2012, Intervernor Fund Grant

Schedule Page: 232 Line No.: 23 Column: d

$26,462 charged to Account 449.1; The residual balance of the local SB408 Multnomah County Business Income Tax deferral vintage year 2007 was combined with the vintage year 2011 balance in Account 229, Accumulated Provision for Rate Refunds.

Schedule Page: 232 Line No.: 29 Column: c

The net credit deferral for the quarter is the result of bid fees received for proposals submitted during the integrated resource planning process.

Schedule Page: 232 Line No.: 29 Column: f

Deferral of costs associated with an Independent Evaluator retained to assist in the design, implementation, evaluation and reporting on Request for Proposals submitted during the integrated resource planning process.

Schedule Page: 232 Line No.: 32 Column: c

Reclassified credit balance in Account 182.3 Regulatory Assets to Account 254 Regulatory Liabilities.

Schedule Page: 232.1 Line No.: 7 Column: c

The residual balance of $37,752 remaining after the authorized amortization period was transfered to the Residual Deferred Account pursuant to OPUC Order No.10-279 dated July 23, 2010

Schedule Page: 232.1 Line No.: 8 Column: c

The residual balance of $75,372 remaining after the authorized amortization period was transfered to the Residual Deferred Account pursuant to OPUC Order No.10-279 dated July 23, 2010

Schedule Page: 232.1 Line No.: 20 Column: c

The residual credit balance of $12,511 remaining after the authorized amortization period was transferred to the Residual Deferred Account, pursuant to OPUC Order No. 10-279 dated July 23, 2010.

Schedule Page: 232.1 Line No.: 20 Column: e

$11,128 charged to Account 456; $13 charged to Account 431.

Schedule Page: 232.1 Line No.: 24 Column: d

Amounts charged to Accounts 407.3, 254, and 182.3. See Footnote on Line 24, Column (e) for details

Schedule Page: 232.1 Line No.: 24 Column: e

$867,739 was charged to Account 407.3. The balance represents the transfer of combined residual balances in Accounts 182.3 and 254 past their authorized amortization period pursuant to OPUC Order No. 10-279, dated July 23, 2010.

Schedule Page: 232.1 Line No.: 32 Column: f

Balance represents the deferral of glass insulator costs for treatment as capitalized costs for amortization over the average useful life of transmission poles.OPUC Order No. 10-478, dated 12.17.2010.

Schedule Page: 232.1 Line No.: 37 Column: e

$1,583,582 was charged to Account 219; $318,684 was charged to Account 926 due to an Earned Time Off adjustment.

Schedule Page: 232.1 Line No.: 41 Column: c

The residual credit balance in Account 182.3 Regulatory Asset was transferred to Account 242 Miscellaneous Current and Accrued Liabilities.

Schedule Page: 232.2 Line No.: 2 Column: e

Reclassified balance to current liability account 254

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

Reclassed debit balance in Account 242 Miscellaneous Current and Accrued Liabitilieis to

Account 182.3 Regulatory Asssets.

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

Balancing account to track the difference between actual collections from customers and the revenue requirement related to the increase in depreciation/amortization expense and the decommissioning costs due to the planned Boardman plant closure changing from the year 2040 to the year 2020.

Schedule Page: 232.2 Line No.: 8 Column: c

The residual credit balance of $114,879 remaining after the authorized amortization period was transferred to the Residual Defered Account pursuant to OPUC Order No. 10-279 dated July 23, 2010.

Schedule Page: 232.2 Line No.: 17 Column: f

Deferral of the revenue requirement associated with four capital projects as part of the Second Revenue Requirement Stipulation in the UE 215 General Rate Case.OPUC Order No. 10-478, dated 12.17.2010.

Schedule Page: 232.2 Line No.: 21 Column: f

Deferral of the revenue requirement related to the incremental costs of the Baldock Solar Project.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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						
2	Misc. Undistributed Charges	527,372	1,948,563	Various	2,342,715	133,220
3						
4	Net Co-owner / Trust Contributi	3,108,071	87,782,558	Various	90,323,890	566,739
5						
6	Pebble Springs AFDC &					
7	Tax Credit Sale -					
8	amort. over service lives					
9	of related property	226,033	1,266	421/425	227,299	
10						
11	Deferred Wheeling Costs -					
12	amort. over 25 yrs through 2012	146,073		565	146,073	
13						
14	Deferred Rent - WTC Tenant					
15	amort. through 2015	55,731		418	14,276	41,455
16						
17	Deferred Revolving Credit					
18	Agreement Fees					
19	amort. through 2017	1,588,894	1,540,235	431	559,602	2,569,527
20						
21	Dispatchable Generation					
22	various amort. periods from					
23	2005 and extending through 2021	8,027,789	2,727,796	903	2,643,695	8,111,890
24						
25	LID Receivable from WTC Tenants					
26	amort. over 20 yrs through 2029	107,806		418	5,989	101,817
27						
28	Colstrip - Lime Contract					
29	amort. over 4 yrs. 2011 - 2014	1,850,000		Various	652,172	1,197,828
30						
31	Utility Property Sales-					
32	Selling Expenses		1,200,000			1,200,000
33						
34						
35						
36						
37						
38						
39						
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42						
43						
44						
45						
46						
47	Misc. Work in Progress	114,645				248,138
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	15,752,414				14,170,614

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Property Related	12,618,109	4,029,595
3	Regulatory Liabilities	14,338,937	20,217,265
4	Employee Benefits	135,056,855	162,721,343
5	Price Risk Management	153,152,250	79,937,501
6	Tax Credits & NOL's	56,757,746	55,294,605
7	Other	9,949,559	11,720,925
8	TOTAL Electric (Enter Total of lines 2 thru 7)	381,873,456	333,921,234
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	5,774,814	5,613,748
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	387,648,270	339,534,982

Notes

Line 7 - Other

	Ending Bal 12/31/2011	Ending Bal 12/31/2012
Bad Debt Expense	$2,206,951	$2,120,104
Nuclear Decommissioning Trust	992,542	1,170,507
Renewable Energy Development	3,404,487	4,445,738
Miscellaneous	3,345,487	3,984,576
Total Line 7 - Other	$9,949,560	$11,720,925

Line 17 - Other NonUtility	Ending Bal 12/31/2011	Ending Bal 12/31/2012
Property Related	$4,837,098	$5,134,281
Software Costs	334,170	0
Miscellaneous	603,546	479,467
Total Line 17 - Other NonUtuility	$5,774,814	$5,613,748

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

FOOTNOTE DATA

Schedule Page: 234 Line No.: 1 Column:

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

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
75,556,272	832,388,455					2
						3
75,556,272	832,388,455					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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	49,120
12	SUBTOTAL Account 210	49,120
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	1,102,665
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	9,956,413
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
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38		
39		
40	TOTAL	16,366,513

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

Represents the assumption of PGE's current tax liability by the Company's former parent company 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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	7,776,148
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
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21		
22	TOTAL	7,776,148

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

The majority of the decrease in account 214 is due mainly to the transfer of the Capital Stock Expense related to the issuance of the 7.75% Series No Par Cumulative Preferred Stock to Other Interest Expense (account 431 - total transfer of $305,275). In 2003, upon issuance of FAS 150, PGE's 7.75% Series Preferred Stock was reclassified from equity to debt. The FASB concluded that mandatorily redeemable preferred stock (like PGE's) had more elements of fixed rate debt than equity. In accordance with the FASB's view of preferred stock as debt, the Capital Stock Expense in equity account 214 was transferred to expense account 431.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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			
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	Pollution Control Bonds (Guaranteed by Company) -		
27	Port of Morrow, OR Series 1998A 5% Due 5/1/2033	23,600,000	604,452
28	City of Forsyth, MT Series 1998A 5% Due 5/1/2033	97,800,000	2,615,167
29			
30	SUBTOTAL ACCOUNT 221	1,736,400,000	29,550,782
31			
32	ACCOUNT 224 - OTHER LONG TERM DEBT		
33	TOTAL	1,736,507,806	29,550,782

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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			
2	City of Portland Improvement District Loan	107,806	
3	SUBTOTAL ACCOUNT 224	107,806	
4			
5			
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32			
33	TOTAL	1,736,507,806	29,550,782

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
10/28/2002	10/25/2012	10/28/2002	10/25/2012		4,644,198	3
08/12/1991	08/11/2021	08/12/1991	08/11/2021	20,000,000	1,862,003	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	3,437,498	9
						10
05/26/2006	05/01/2031	05/26/2006	05/01/2031	100,000,000	6,260,003	11
05/26/2006	05/01/2036	05/26/2006	05/01/2036	175,000,000	11,042,497	12
05/16/2007	06/01/2039	05/16/2007	06/01/2039	170,000,000	9,860,004	13
09/19/2007	10/01/2037	09/19/2007	10/01/2037	130,000,000	7,552,993	14
						15
12/12/2007	03/01/2018	12/12/2007	03/01/2018	75,000,000	4,350,000	16
04/15/2008	04/01/2013	04/15/2008	04/01/2013	50,000,000	2,225,004	17
						18
						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	18,300,000	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	2,421,995	24
06/15/2010	06/15/2017	06/15/2010	06/15/2017	58,000,000	2,209,800	25
						26
05/28/1998	05/01/2033	05/28/1998	05/01/2033	23,600,000	1,179,997	27
05/28/1998	05/01/2033	05/28/1998	05/01/2033	97,800,000	4,890,000	28
						29
				1,636,400,000	99,124,496	30
						31
						32
				1,636,501,817	99,124,496	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)	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
11/16/2009	11/16/2029			101,817		2
				101,817		3
						4
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						29
						30
						31
						32
				1,636,501,817	99,124,496	33

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)	141,315,881
2		
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion, & Amortization	-13,865,553
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Depreciation, Depletion, & Amortization	
11	Regulatory Debits	176,970,784
12	Other (See Footnote)	89,049,096
13		
14	Income Recorded on Books Not Included in Return	
15	Price Risk Management and Mark-to-Market	-174,190,284
16	Depreciation, Depletion, & Amortization	-9,766,737
17	Regulatory Credits	-6,705,137
18	Other (See Footnote)	-6,984,493
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion, & Amortization	-83,957,101
21	State & Local Tax Deduction	-626,644
22	Other (See Footnote)	-3,232,639
23		
24		
25		
26		
27	Federal Tax Net Income	108,007,173
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @ 35%	37,802,511
30	Federal Energy Credit	-28,509,949
31	RTA and FAS 109 Adjustment	5,320,501
32	APIC Tax Adjustment	856,540
33	Other Miscellaneous Tax Adjustment	90,230
34	Total Federal Income Tax - PGE	15,559,833
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 12 Column: b

Qualified NDT	$ 432,040
Travel & Entertainment	430,112
Politcal Activity	725,479
Bad Debts	52,658
Employee Benefits	10,979,202
Federal Provision	45,998,629
Unamortized loss on reacquired debt	6,063,588
State Provision	17,741,674
Miscellaneous	6,625,714
Total Other	$ 89,049,096

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

IRC Section 199 Domestic Production Activities Deduction	($ 1,789,225)
Stock Incentive Plans	(2,664,721)
Key Man Insurance Proceeds	(1,745,578)
Miscellaneous	(784,969)
Total Other	($ 6,984,493)

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

Dividend Received Deduction	($ 150,000)
Bad Debts	(339,616)
Utility Land Sale	(1,204,971)
Glendale Settlement	(1,200,000)
Miscellaneous	(338,052)
Total Other	($ 3,232,639)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	125,001		518,743	518,743	
3	Income Tax	-48,312	12,303,698	14,703,292	4,164,564	199,567
4	Foreign Insurance Excise Tax					
5	FICA (Employer Share)	1,372,935		16,446,025	16,454,594	
6	Unemployment	4,129		156,095	151,282	
7	Power License	720,436	1	1,403,588	1,455,913	
8	Superfund Tax					
9	SUBTOTAL Federal	2,174,189	12,303,699	33,227,743	22,745,096	199,567
10	State of Montana:					
11	Income Tax	230,604	108,654	229,136	320,000	
12	Elec. Energy Producers Tax	199,667		673,298	660,668	
13	Property Taxes	2,158,154		5,114,792	4,718,438	
14	SUBTOTAL Montana	2,588,425	108,654	6,017,226	5,699,106	
15	State of Oregon:					
16	Corp Excise Tax			-259,422	100,000	49,091
17	Property Taxes		20,588,484	42,090,844	42,569,420	
18	City Taxes and Licenses	3,635,630		42,063,146	42,222,964	
19	Public Utility Comm Fees			4,581,169	4,581,169	
20	Department of Energy		711,549	1,311,815	1,200,522	
21	Department of Enviro Quality	660,837		-3,677	284,645	
22	Unemployment	51,159		2,087,741	2,089,650	
23	Water Power Fee		541,911	1,259,958	551,194	
24	Transportation Tax	305,609		1,316,700	1,296,943	
25	Workers Comp Assessment	62,280		218,114	231,065	
26	County & City Income Tax	108,256		290,505	349,000	24,470
27	SUBTOTAL Oregon	4,823,771	21,841,944	94,956,893	95,476,572	73,561
28	State of Washington:					
29	Property Taxes	40,800		36,072	40,872	
30	Sales Tax					
31	SUBTOTAL Washington	40,800		36,072	40,872	
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	9,627,185	34,254,297	134,237,934	123,961,646	273,128

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

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					518,743	2
2,231,095	3,844,810	16,674,750			-1,971,458	3
		9,600			-9,600	4
1,364,365		10,016,583			6,429,442	5
8,942		86,784			69,311	6
668,111	1				1,403,588	7
						8
4,397,514	3,844,811	26,787,717			6,440,026	9
						10
139,740	108,654	239,023			-9,887	11
212,297		401,367			271,931	12
2,554,507		3,847,368			1,267,424	13
2,906,544	108,654	4,487,758			1,529,468	14
						15
4,973,202	5,283,533	-70,367			-189,055	16
434,995	21,502,056	40,650,529			1,440,314	17
3,475,812		42,081,393			-18,247	18
					4,581,169	19
	600,256	1,311,815				20
372,515					-3,677	21
49,250		1,160,716			927,025	22
	-166,853				1,259,958	23
325,366		1,316,700				24
49,329		127,479			90,635	25
779,002	704,771	314,026			-23,521	26
10,459,471	27,923,763	86,892,291			8,064,601	27
						28
36,000		36,072				29
						30
36,000		36,072				31
						32
						33
						34
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						38
						39
						40
17,799,529	31,877,228	118,203,838			16,034,095	41

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

Federal Tax Return Interest	($ 23,135)
Tax Payment from Subsidiary	208,896
Tax Penalty	13,806
Total Adjustments	$ 199,567

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

Tax Payment from Subsidiary

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

Tax Payment from Subsidiary

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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%						
6							
7							
8	TOTAL						
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
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17							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
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			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	308	921	308		
2						
3	Accelerated cost recovery system					
4	tax benefit sale - amort. over					
5	service lives of related					
6	property	226,034	186	226,034	751,000	751,000
7						
8	Tenant sub-lease security deposits	56,224	418	17,824	11,272	49,672
9						
10	Deferred premiums on power	114,188	547/555	1,199,558	1,085,370	
11	options sold					
12						
13	Deferred Liability for Transferred					
14	Non-Qualified Plan Benefits	856,114	421	60,231		795,883
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
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33						
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41						
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44						
45						
46						
47	TOTAL	1,252,868		1,503,955	1,847,642	1,596,555

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
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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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	553,945,938	87,438,082	38,877,526
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	553,945,938	87,438,082	38,877,526
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	553,945,938	87,438,082	38,877,526
10	Classification of TOTAL			
11	Federal Income Tax	464,583,958	61,720,883	31,024,332
12	State Income Tax	81,809,481	24,453,428	6,926,236
13	Local Income Tax	7,552,499	1,263,771	926,958

NOTES

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

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (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
		182.3	9,425,135	254	4,845,280	597,926,639	2
							3
							4
			9,425,135		4,845,280	597,926,639	5
							6
							7
							8
			9,425,135		4,845,280	597,926,639	9
							10
			7,709,421		3,072,113	490,643,201	11
			1,552,910		1,723,657	99,507,420	12
			162,804		49,510	7,776,018	13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Property Related	36,004,805		
4	Price Risk Management	7,860,823	1,135,861	6,513,628
5	Regulatory Assets	273,359,234	31,258,228	80,456,975
6	Regulatory Liabilities	-7,853,696		420,446
7	Other	18,997,193	908,169	2,875,405
8				
9	TOTAL Electric (Total of lines 3 thru 8)	328,368,359	33,302,258	90,266,454
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	1,505,091		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	329,873,450	33,302,258	90,266,454
20	Classification of TOTAL			
21	Federal Income Tax	272,057,266	21,944,646	73,077,028
22	State Income Tax	52,763,766	10,982,139	15,720,006
23	Local Income Tax	5,052,418	375,473	1,469,420

NOTES

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
		254	6,354,297	182.3	4,060,690	33,711,198	3
						2,483,056	4
						224,160,487	5
		190	988,101	190	9,262,243		6
				219	762	17,030,719	7
							8
			7,342,398		13,323,695	277,385,460	9
							10
							11
							12
							13
							14
							15
							16
							17
124,481	336,961	236	135	236	50	1,292,526	18
124,481	336,961		7,342,533		13,323,745	278,677,986	19
							20
43,599	240,905		6,128,509		10,486,986	225,086,055	21
76,708	87,506		1,107,207		2,668,969	49,576,863	22
4,174	8,550		106,817		167,790	4,015,068	23

NOTES (Continued)

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

	Balance at Beginning of Year	Balance at End of Year
ASC 980 Mark-to-Market	67,800,948	28,160,355
Price Risk Mgmt Deferral	77,490,478	49,294,090
ASC 715 Pension & Post Retirement	116,451,421	128,235,589
Miscellaneous	11,616,387	18,470,453
Total Other	$273,359,234	$224,160,487

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

	Balance at Beginning of Year	Balance at End of Year
Unamortized Loss on Reacquired Debt	$ 11,068,561	$ 8,783,234
Prepaid Property Tax	7,871,482	$ 7,765,290
Other	57,150	482,195
Total Other	$ 18,997,193	$ 17,030,719

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

	Balance at Beginning of Year	Balance at End of Year
Trust-Owned Life Insurance Gain/Loss	$ 881,388	$ 895,494
Other	623,703	397,032
Total Other	$ 1,505,091	$ 1,292,526

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

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Excess Deferred Taxes	3,972,406	190	224,992		3,747,414
2						
3	Surplus CAA Allowances	672,731			116	672,847
4	(per OPUC Order No. 552 dtd 3/31/1993)					
5						
6	BPA Subscription Power - Balancing Account	8,819,584	456	58,727,746	58,177,508	8,269,346
7	(per OPUC Order No. 08-175 dtd 3/20/2008)	1,926,763	456	881,122	67,205	1,112,846
8						
9	Gain on Asset Sales	833,569			490,158	1,323,727
10	(per OPUC Order No. 01-777 dtd 8/31/2001)					
11						
12	Gain on TRC Sales	1,864,141			27,589	1,891,730
13	(per OPUC Order No. 07-083 dtd 3/5/2007)					
14						
15	Power Cost Adjustment (Oct 2001 - Dec 2002)	117,260	555/182.3	117,475	215	
16	(per Advice 10-22A dtd 12/28/2010;					
17	amortization period: 01/01/2011 - 12/31/2011)					
18						
19	Asset Retirement Obligations:	36,128,174	407.3	1,504,342	4,771,377	39,395,209
20	Balancing Account					
21						
22	Coyote Springs Major Maintenance Deferral	3,476,233	407.4	3,432,955	2,044,272	2,087,550
23	(per OPUC Order No. 01-777 dtd 8/31/2001;					
24	reauthorization OPUC Order No. 10-478					
25	dtd 12/17/2010)					
26						
27	ISFSI Pollution Control Tax Credit Deferral	6,610,963	407.4	395,825	2,274,749	8,489,887
28	(per OPUC Order No. 05-136 dtd 3/15/2005)					
29	amortization per Advice 10-22A dtd 12/28/2010;					
30	amortization period: 01/01/2011 - 12/31/2011)					
31						
32	Zero Interest Program Loan Repayments	1,090,555			207,193	1,297,748
33	(per Advice No. 05-19 dtd 12/20/2005)					
34						
35	Schedule 110 Energy Efficiency - Balancing Accout	703,367			194,434	897,801
36	(per Advice No. 07-25 dtd 5/20/2008)					
37						
38	SB1149 Residual Balance	60,757	407.4	90,226	29,469	
39	(per Advice 10-22A dtd 12/28/2010;					
40	amortization period: 01/01/2011 - 12/31/2011)					
41	TOTAL	68,548,059		67,359,424	72,193,506	73,382,141

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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						
2	Direct Access Open Enrollment - 2010	36,668	447	82,164	45,496	
3	(per Advice 10-22A dtd 12/28/2010;					
4	amortization period: 01/01/2011 - 12/31/2011)					
5						
6	Direct Access Open Enrollment - 2011	1,132,525	447	1,054,744	12,216	89,997
7	(per Advice 10-23 dtd 11/15/2010 Tariff					
8	Schedule 128)					
9						
10	Direct Access Open Enrollment - 2012				493,801	493,801
11	(per Advice 11-31 dtd 11/15/2011)					
12						
13	Sunway 3 Investment Deferral	841,270	407.4	45,480		795,790
14	(per UM 1480 dtd 4/01/2010;					
15	amortization over 20 years)					
16						
17	Baldock Solar - Gain on Sale				1,904,345	1,904,345
18	(per OPUC Order No. 12-063 dtd 2/28/2012)					
19						
20	Multnomah County Business Income Tax Balancing		407.4	538,031	1,450,762	912,731
21	(per Advice No. 11-27 dtd 10/27/2012; Schedule					
22	6; OAR 860-022-0045)					
23						
24	Interest on Portland Energy Solutions Note	261,093	407.4	264,322	2,601	-628
25	(per OPUC Order No. 02-280 dtd 4/19/2002)					
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	68,548,059		67,359,424	72,193,506	73,382,141

Schedule Page: 278 Line No.: 15 Column: c

Credit to Account 555 of $113,955. The remaining residual balance after the authorized amortization period of $3,250 was transferred to the Residual Deferred Account in Account 182.3, pursuant to OPUC Order No. 10-279 dated July 23, 2010.

Schedule Page: 278 Line No.: 35 Column: e

Includes amounts transferred from 182.3, Regulatory Assets.

Schedule Page: 278 Line No.: 38 Column: e

The debit residual balance remaining after the authorized amortization period of $29,415 was transferred to the Residual Deferred Account in Account 182.3, pursuant to OPUC Order No.10-279 dated July 23, 2010

Schedule Page: 278.1 Line No.: 2 Column: e

The debit residual balance remaining after the authorized amortization period of $45,496 was transferred to the Residual Deferred Account in Account 182.3, pursuant to OPUC Order No. 10-279 dated July 23, 2010.

Schedule Page: 278.1 Line No.: 17 Column: e

In January 2012, PGE completed construction of a $10 million, 1.75 MW solar power electric generating facility, which was sold to, and simultaneously leased-back from, a financial institution. A gain realized from the sale was deferred per Order No.12-063.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	804,944,928	835,332,617
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	608,842,827	619,653,004
5	Large (or Ind.) (See Instr. 4)	225,347,823	227,626,835
6	(444) Public Street and Highway Lighting	17,956,680	17,782,195
7	(445) Other Sales to Public Authorities		738
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,657,092,258	1,700,395,389
11	(447) Sales for Resale	72,173,577	83,763,858
12	TOTAL Sales of Electricity	1,729,265,835	1,784,159,247
13	(Less) (449.1) Provision for Rate Refunds	-7,763,527	5,955,065
14	TOTAL Revenues Net of Prov. for Refunds	1,737,029,362	1,778,204,182
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,587,422	1,854,756
17	(451) Miscellaneous Service Revenues	2,303,654	2,351,445
18	(453) Sales of Water and Water Power	4,641	-17,839
19	(454) Rent from Electric Property	7,406,637	6,763,866
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	66,586,129	37,242,620
22	(456.1) Revenues from Transmission of Electricity of Others	7,253,320	6,068,446
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	86,141,803	54,263,294
27	TOTAL Electric Operating Revenues	1,823,171,165	1,832,467,476

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

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
7,505,405	7,732,514	723,440	719,977	2
				3
6,853,728	6,959,786	103,520	102,695	4
3,474,566	3,553,947	261	254	5
110,736	110,565	246	244	6
	14		1	7
				8
				9
17,944,435	18,356,826	827,467	823,171	10
3,188,338	2,978,442	43	44	11
21,132,773	21,335,268	827,510	823,215	12
				13
21,132,773	21,335,268	827,510	823,215	14

Line 12, column (b) includes $ -4,167,000 of unbilled revenues.

Line 12, column (d) includes -31,375 MWH relating to unbilled revenues

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

Includes $16,503,790 in revenue related to the delivery of 438,470 megawatt hours to customers of Energy 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 2012, the "transition adjustment" credits provided to many commercial and industrial customers were 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 $11,831,059 in revenue related to the delivery of 348,805 megawatt hours to customers of Energy 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 a 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 2011, the "transition adjustment" credits provided to many commercial and industrial customers were 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: b

Includes $16,771,151 in revenue related to the delivery of 808,238 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2012, the "transition adjustment" credits provided to many commercial and industrial customers were 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 $8,723,100 in revenue related to the delivery of 639,633 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2011, the "transition adjustment" credits provided to many commercial and industrial customers were 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.: 17 Column: b

Miscellaneous Service Revenues include charges billed in accordance with PGE Tariff Schedule 300 *Charges 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

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

Miscellaneous Service Revenues include charges billed in accordance with PGE Tariff Schedule 300 *Charges 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

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

Other Electric Revenues consist of the following:

	2012	2011
BPA Subscription Power - Balancing Account	$ 59,608,867	$ 51,182,528
Biglow Canyon Phase 2 Deferral	(25,662)	(4,684,160)
Biglow Canyon Phase 3 Deferral	(900,395)	(17,262,014)
Residential Sch 123 SNA Deferral	(862,556)	(923,112)
Small Nonresidential Sch 123 SNA Deferral	(1,235,988)	(2,240,146)
Sch 123 LRRA Deferral	-	(285,043)
Baldock Solar	350,678	-
Boardman Decomissioning Balancing Account	(451,573)	-
EE Program Delivery Contractor Services	1,725,828	1,701,107
PGE Share of Boardman Ash Sales	322,790	-
Park Revenues	526,923	515,797
Steam Sales	1,553,085	1,695,644
Gas for Resale	-	276,006
Wheeling Resale	5,296,820	6,275,911
Other - net	677,310	990,103
Totals	$ 66,586,129	$ 37,242,620

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

Other Electric Revenues consist of the following:

	2011	2010
BPA Subscription Power - Balancing Account	$ 51,182,528	$50,928,888
Biglow Canyon Phase 2 Deferral	(4,684,160)	(6,253,583)
Biglow Canyon Phase 3 Deferral	(17,262,014)	17,763,375
Residential Sch 123 SNA Deferral	(923,112)	4,002,593
Small Nonresidential Sch 123 SNA Deferral	(2,240,146)	1,830,290
Sch 123 LRRA Deferral	(285,043)	-
Power Cost Adjustment Mechanism	-	1,118,929
Boardman Power Cost Deferral	-	1,276,262
EE Program Delivery Contractor Services	1,701,106	1,457,297
PGE Share of Boardman Ash Sales	-	382,423
Income from Salmon Springs Hospitality Group	-	346,613
Park Revenues	515,797	500,395
Steam Sales	1,695,644	1,747,435
Gas for Resale	276,006	405,903
Oil for Resale	-	5,147,422
Wheeling Resale	6,275,911	5,390,250
Other - net	990,103	1,125,570
Totals	$ 37,242,620	$87,170,062

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

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	7,513,184	805,712,674	722,671	10,396	0.1072
3	12 Critical Peak Pricing Pilot	7,929	835,014	769	10,311	0.1053
4	15 Outdoor Area Lighting	6,847	1,510,240			0.2206
5	Residential Unbilled Revenue	-22,555	-3,113,000			0.1380
6	TOTAL Account 440	7,505,405	804,944,928	723,440	10,375	0.1072
7						
8	General Comm. and Ind. Sales:					
9	15 Comm. Outdoor Lighting	15,984	2,736,858			0.1712
10	32 Small Nonresidential	1,539,577	159,791,078	87,333	17,629	0.1038
11	38 Optional Time of Day -	28,897	3,496,411	283	102,110	0.1210
12	Large Nonresidential					
13	47 Irrigation - Drainage - Small	18,693	2,509,387	2,095	8,923	0.1342
14	49 Irrigation - Drainage - Large	59,569	5,484,627	1,031	57,778	0.0921
15	83-S Large Nonresidential	2,719,697	230,086,407	11,039	246,372	0.0846
16	85-S Large Nonresidential	2,004,567	154,816,250	1,213	1,652,570	0.0772
17	89-S Large Nonresidential	460,712	34,135,075	73	6,311,123	0.0741
18	485-S COS Opt-Out - Lrg. Nonresid		7,465,726	111		
19	485-S COS Opt-Out - Lrg. Nonresid	2,088	131,003	1	2,088,000	0.0627
20	489-S COS Opt-Out - Lrg. Nonresid	11,947	463,869	1	11,947,000	0.0388
21	489-S COS Opt-Out - Lrg. Nonresid		1,012,136	6		
22	515-S DAS - Outdoor Area Lighting		7,791			
23	532-S DAS - Small Nonresidential		287,342	118		
24	583-S DAS - Large Nonresidential		3,173,012	166		
25	585-S DAS - Large Nonresidential		3,563,734	48		
26	589-S DAS - Large Nonresidential		473,121	2		
27	Gen Comm. & Ind. Unbilled Revenue	-8,003	-791,000			0.0988
28	TOTAL Account 442 - Small	6,853,728	608,842,827	103,520	66,207	0.0888
29						
30	Large Industrial Power Sales:					
31	75 Partial Requirements Service	592,032	20,485,516	1	592,032,000	0.0346
32	85-P Large Nonresidential	219,856	16,292,917	120	1,832,133	0.0741
33	89-T Large Nonresidential	294,503	18,592,450	6	49,083,833	0.0631
34	89-P Large Nonresidential	2,369,030	153,976,792	87	27,230,230	0.0650
35	485-P COS Opt-Out - Lg. Nonreside		216,205	3		
36	489-T COS Opt-Out - Lg. Nonreside		2,571,054	2		
37	489-P COS Opt-Out - Lg. Nonreside		8,899,608	11		
38	583-P DAS - Large Nonresidential		76,406	2		
39	585-P DAS - Large Nonresidential		3,460,290	26		
40	589-P DAS - Large Nonresidential		1,050,588	3		
41	TOTAL Billed	17,975,810	1,661,259,258	827,467	21,724	0.0924
42	Total Unbilled Rev.(See Instr. 6)	-31,375	-4,167,000	0	0	0.1328
43	TOTAL	17,944,435	1,657,092,258	827,467	21,686	0.0923

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	-855	-274,000			0.3205
2	TOTAL Account 442 - Large	3,474,566	225,347,826	261	13,312,513	0.0649
3						
4	Various Public Street and					
5	Highway Lighting:					
6	Street Lighting	110,698	17,945,680	246	449,992	0.1621
7	Street Lighting Unbilled Rev	38	11,000			0.2895
8	TOTAL Account 444	110,736	17,956,680	246	450,146	0.1622
9						
10	Other Sales to Public Authorities					
11	Communication Devices Electr					
12	TOTAL Account 445					
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	17,975,810	1,661,259,258	827,467	21,724	0.0924
42	Total Unbilled Rev.(See Instr. 6)	-31,375	-4,167,000	0	0	0.1328
43	TOTAL	17,944,435	1,657,092,258	827,467	21,686	0.0923

Schedule Page: 304 Line No.: 15 Column: a
Rate Schedule 83 complete title: Large Nonresidential Standard Service (31 - 200 kW).

Schedule Page: 304 Line No.: 16 Column: a
Rate schedule 85 complete title: Large Nonresidential Standard Service (201 - 1,000 kW).

Schedule Page: 304 Line No.: 17 Column: a
Rate schedule 89 complete title: Large Nonresidential (>1,000 kW) Standard Service.

Schedule Page: 304 Line No.: 18 Column: a
Rate Schedule 485 complete title: Large Nonresidential (<1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 18 Column: b
Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 19 Column: a
Rate Schedule 485 complete title: Large Nonresidential (<1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 19 Column: b
Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. In 2012, this customer purchased its energy from PGE.

Schedule Page: 304 Line No.: 20 Column: a
Rate Schedule 489 complete title: Large Nonresidential (>1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 20 Column: b
Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. In 2012, this customer purchased its energy from PGE.

Schedule Page: 304 Line No.: 21 Column: a
Rate Schedule 489 complete title: Large Nonresidential (>1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 21 Column: b
Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 22 Column: b
Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE serves 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 serves 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 (31 - 200 kW).

Schedule Page: 304 Line No.: 24 Column: b
Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE serves these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 25 Column: a
Rate Schedule 585 complete title: Large Nonresidential Direct Access Service (201 - 1,000 kW).

Schedule Page: 304 Line No.: 25 Column: b
Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE serves these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 26 Column: a
Rate Schedule 589 complete title: Large Nonresidential (>1,000 kW) Direct Access Service.

Schedule Page: 304 Line No.: 26 Column: b

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

Schedule Page: 304 Line No.: 32 Column: a

Rate schedule 85 complete title: Large Nonresidential Standard Service (201 - 1,000 kW).

Schedule Page: 304 Line No.: 33 Column: a

Rate schedule 89 complete title: Large Nonresidential (>1,000 kW) Standard Service.

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

Rate schedule 89 complete title: Large Nonresidential (>1,000 kW) Standard Service.

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

Rate Schedule 485 complete title: Large Nonresidential (<1,000 kW) Cost of Service Opt-out.

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

Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves 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 schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves 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 schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves 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 (31 - 200 kW).

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

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

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

Rate Schedule 585 complete title: Large Nonresidential Direct Access Service (201 - 1,000 kW).

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

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

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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.
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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	Barclays Bank	SF	WSPP-1	NA	NA	NA
8	Black Hills Power	SF	WSPP-1	NA	NA	NA
9	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
10	BP Energy Company	SF	PGE-11	NA	NA	NA
11	Brookfield Energy Marketing LP	SF	WSPP-1	NA	NA	NA
12	Burbank, City of	SF	WSPP-1	NA	NA	NA
13	California ISO	SF	CAISO	NA	NA	NA
14	Calpine Energy Services	SF	EEI	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

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					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, Washington	SF	WSPP-1	NA	NA	NA
3	Citigroup Energy Inc.	SF	WSPP-1	NA	NA	NA
4	Clatskanie County PUD, Washington	SF	WSPP-1	NA	NA	NA
5	Constellation Energy Commodities	SF	EEI	NA	NA	NA
6	CP Energy Marketing	SF	WSPP-1	NA	NA	NA
7	DB Energy Trading LLC	SF	WSPP-1	NA	NA	NA
8	Douglas County PUD Washington	SF	WSPP-1	NA	NA	NA
9	EDF Trading NA	SF	WSPP-1	NA	NA	NA
10	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
11	Glendale, City of	LF	PGE-78	20	20	19
12	Glendale, City of	SF	WSPP-1	NA	NA	NA
13	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
14	Iberdrola Renewables	SF	EEI	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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

SALES FOR RESALE (Account 447)

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	(a)	(b)	(c)	(d)	(e)	(f)
1	Idaho Power Company	SF	WSPP-1	NA	NA	NA
2	J. Aron Company	SF	EEI	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 Power	SF	WSPP-1	NA	NA	NA
6	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
7	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
8	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
9	NASDAQ OMX Commodities	SF	WSPP-1	NA	NA	NA
10	NaturEner	SF	WSPP-1	NA	NA	NA
11	Nevada Power	SF	WSPP-1	NA	NA	NA
12	NextEra Energy Solutions Inc	SF	WSPP-1	NA	NA	NA
13	Noble Americas Gas & Power Corp	SF	EEI	NA	NA	NA
14	Northern California Power Agency	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)

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1	NorthPoint Energy Solutions	SF	WSPP-1	NA	NA	NA
2	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
3	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
4	Pacific Northwest Generating Company	SF	WSPP-1	NA	NA	NA
5	PacifiCorp	LU	PGE-11	NA	NA	NA
6	PacifiCorp	SF	EEI	NA	NA	NA
7	Powerex	SF	PGE-11	NA	NA	NA
8	PPL Energy Plus	SF	EEI	NA	NA	NA
9	PUD No. 1 of Clark County	SF	WSPP-1	NA	NA	NA
10	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
11	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
12	Redding, City of	SF	WSPP-1	NA	NA	NA
13	Roseville, City of	SF	WSPP-1	NA	NA	NA
14	Sacramento Municipal Utility Distric	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES FOR RESALE (Account 447)

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	(a)	(b)	(c)	(d)	(e)	(f)
1	San Diego Gas & Electric Company	SF	WSPP-1	NA	NA	NA
2	Seattle City Light	SF	WSPP-1	NA	NA	NA
3	Shell Energy NA	SF	WSPP-1	NA	NA	NA
4	Sierra Pacific	SF	WSPP-1	NA	NA	NA
5	Silicon Valley Power	SF	WSPP-1	NA	NA	NA
6	Snohomish County PUD Washington	SF	WSPP-1	NA	NA	NA
7	Southern California Edison	SF	EEI	NA	NA	NA
8	Tacoma, City of	SF	WSPP-1	NA	NA	NA
9	Tenaska Power Services	SF	WSPP-1	NA	NA	NA
10	The Energy Authority	SF	WSPP-1	NA	NA	NA
11	TransAlta Energy Marketing	SF	EEI	NA	NA	NA
12	TransCanada Power	SF	WSPP-1	NA	NA	NA
13	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
14	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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	Reserve					
2	Direct Access Deferral - 2012					
3	Direct Access Amortization					
4						
5	Portland General Electric Company	SF	OA96137	392		
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
	721,550	-551,823		169,727	2
					3
					4
					5
16,707		284,869		284,869	6
200		5,100	-117,200	-112,100	7
245		3,920		3,920	8
68,707		1,540,592		1,540,592	9
6,464		82,482		82,482	10
5,588		100,303		100,303	11
9,609		178,241		178,241	12
458,920		9,910,361		9,910,361	13
399,344		8,016,163		8,016,163	14
0	721,550	-551,823	0	169,727	
3,198,345	5,772,407	65,059,282	1,172,161	72,003,850	
3,198,345	**6,493,957**	**64,507,459**	**1,172,161**	**72,173,577**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)
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6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
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.
53,831		1,124,891		1,124,891	1
3,004		60,994		60,994	2
81,245		1,831,325		1,831,325	3
62		535		535	4
37,075		640,633		640,633	5
317		7,382		7,382	6
64,989		967,748		967,748	7
600					8
30,733		614,977		614,977	9
8,240		145,657		145,657	10
71,366	3,080,000	1,187,440		4,267,440	11
9,200		993		993	12
22,648		438,825		438,825	13
292,225		7,204,550		7,204,550	14
0	721,550	-551,823	0	169,727	
3,198,345	5,772,407	65,059,282	1,172,161	72,003,850	
3,198,345	**6,493,957**	**64,507,459**	**1,172,161**	**72,173,577**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
25,584		476,738		476,738	1
400		10,200		10,200	2
18,310		424,235		424,235	3
38,149			712,915	712,915	4
74,073		1,096,506		1,096,506	5
61,133		975,872		975,872	6
12,836		411,554		411,554	7
156,240		2,669,476		2,669,476	8
6,000		135,310		135,310	9
2		52		52	10
50		1,700		1,700	11
1,733		30,602		30,602	12
9,191		122,807		122,807	13
3,694		70,757		70,757	14
0	721,550	-551,823	0	169,727	
3,198,345	5,772,407	65,059,282	1,172,161	72,003,850	
3,198,345	**6,493,957**	**64,507,459**	**1,172,161**	**72,173,577**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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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.
7,200		6,470		6,470	1
23,753		545,025		545,025	2
295		6,300		6,300	3
9,957		77,815		77,815	4
17,098			63,041	63,041	5
58,728		972,457		972,457	6
123,816		1,922,080		1,922,080	7
18,527		422,733		422,733	8
8,955		156,946		156,946	9
24,419		523,753		523,753	10
32,136		427,508		427,508	11
28,420		535,499		535,499	12
5		145		145	13
89,326		1,595,861		1,595,861	14
0	721,550	-551,823	0	169,727	
3,198,345	5,772,407	65,059,282	1,172,161	72,003,850	
3,198,345	**6,493,957**	**64,507,459**	**1,172,161**	**72,173,577**	

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

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5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

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7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
21,222		456,188		456,188	1
10,589		107,276		107,276	2
49,557		942,366		942,366	3
3,428		61,524		61,524	4
3,891		112,946		112,946	5
3,536		72,835		72,835	6
276,118		8,674,244		8,674,244	7
2,730		23,910		23,910	8
9,832		186,468		186,468	9
50,093		932,487		932,487	10
136,645		2,980,358		2,980,358	11
63,679		1,275,697		1,275,697	12
44,415		820,955		820,955	13
21,254		275,022		275,022	14
0	721,550	-551,823	0	169,727	
3,198,345	5,772,407	65,059,282	1,172,161	72,003,850	
3,198,345	**6,493,957**	**64,507,459**	**1,172,161**	**72,173,577**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			-120,000	-120,000	1
			-474,295	-474,295	2
			1,107,700	1,107,700	3
					4
10,007	2,692,407	170,624		2,863,031	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	721,550	-551,823	0	169,727	
3,198,345	5,772,407	65,059,282	1,172,161	72,003,850	
3,198,345	**6,493,957**	**64,507,459**	**1,172,161**	**72,173,577**	

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 Line No.: 7 Column: j

Write-off of uncollectible account receivable.

Schedule Page: 310.1 Line No.: 11 Column: b

The contract with the City of Glendale expired 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 Electric Service Suppliers in deficit of the ESS's actual load within the PGE control area.

Schedule Page: 310.3 Line No.: 5 Column: j

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

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

Reserve for settlement of the PNW (Pacific Northwest) Refund case - Docket No. EL01-10-026.

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

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

Schedule Page: 310.5 Line No.: 3 Column: j

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

Schedule Page: 310.5 Line No.: 5 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.

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

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,922,573	4,022,697
5	(501) Fuel	62,410,785	69,315,036
6	(502) Steam Expenses	4,121,523	3,660,073
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	5,415,041	6,092,141
11	(507) Rents	35,391	31,254
12	(509) Allowances	107,712	
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	74,013,025	83,121,201
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	-363,930	3,104,142
16	(511) Maintenance of Structures	696,540	949,776
17	(512) Maintenance of Boiler Plant	5,579,242	5,203,988
18	(513) Maintenance of Electric Plant	12,149,870	11,050,617
19	(514) Maintenance of Miscellaneous Steam Plant	808,375	2,360,138
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	18,870,097	22,668,661
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	92,883,122	105,789,862
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	502,310	194,281
45	(536) Water for Power	542,055	327,371
46	(537) Hydraulic Expenses	4,054,309	3,449,062
47	(538) Electric Expenses	1,154,534	1,024,174
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,694,420	2,138,259
49	(540) Rents	210,586	31,962
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	9,158,214	7,165,109
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	845,924	567,259
54	(542) Maintenance of Structures	74,130	79,044
55	(543) Maintenance of Reservoirs, Dams, and Waterways	866,633	726,888
56	(544) Maintenance of Electric Plant	1,026,929	659,706
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,569,483	2,239,000
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,383,099	4,271,897
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	13,541,313	11,437,006

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Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	2,858,792	7,313,627
63	(547) Fuel	225,046,527	204,684,976
64	(548) Generation Expenses	3,936,873	2,430,171
65	(549) Miscellaneous Other Power Generation Expenses	5,648,558	3,037,578
66	(550) Rents	280,616	283,347
67	TOTAL Operation (Enter Total of lines 62 thru 66)	237,771,366	217,749,699
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	820,014	700,850
70	(552) Maintenance of Structures	95,243	43,736
71	(553) Maintenance of Generating and Electric Plant	29,889,954	24,447,873
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	337,607	468,014
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	31,142,818	25,660,473
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	268,914,184	243,410,172
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	393,220,591	443,015,041
77	(556) System Control and Load Dispatching	229,000	1,010,832
78	(557) Other Expenses	16,306,843	16,733,513
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	409,756,434	460,759,386
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	785,095,053	821,396,426
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,313,489	2,402,389
84			
85	(561.1) Load Dispatch-Reliability	3,088	9,446
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	622,776	647,892
87	(561.3) Load Dispatch-Transmission Service and Scheduling	832,891	746,734
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	142,448	157,556
90	(561.6) Transmission Service Studies		4,540
91	(561.7) Generation Interconnection Studies	225,071	191,289
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	132,092	162,847
94	(563) Overhead Lines Expenses	187,553	836,342
95	(564) Underground Lines Expenses	371	
96	(565) Transmission of Electricity by Others	68,731,405	68,710,884
97	(566) Miscellaneous Transmission Expenses	2,905,354	2,667,110
98	(567) Rents	2,528,352	2,883,272
99	TOTAL Operation (Enter Total of lines 83 thru 98)	78,624,890	79,420,301
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	198,046	70,892
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	1,357,691	1,400,466
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,041,787	828,543
108	(571) Maintenance of Overhead Lines	319,616	894,616
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,917,140	3,194,517
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	81,542,030	82,614,818

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	9,227,369	7,975,466
135	(581) Load Dispatching	1,774,353	1,069,993
136	(582) Station Expenses	499,258	965,510
137	(583) Overhead Line Expenses	757,393	378,721
138	(584) Underground Line Expenses	1,806,597	1,924,681
139	(585) Street Lighting and Signal System Expenses	589,884	1,653,750
140	(586) Meter Expenses	1,709,967	1,757,941
141	(587) Customer Installations Expenses	2,088,869	1,963,468
142	(588) Miscellaneous Expenses	8,605,835	5,689,758
143	(589) Rents	1,523,052	1,543,511
144	TOTAL Operation (Enter Total of lines 134 thru 143)	28,582,577	24,922,799
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	27,199	333,858
147	(591) Maintenance of Structures	142,928	160,104
148	(592) Maintenance of Station Equipment	2,985,908	2,710,470
149	(593) Maintenance of Overhead Lines	31,150,559	30,386,262
150	(594) Maintenance of Underground Lines	3,856,091	4,382,927
151	(595) Maintenance of Line Transformers	314,156	164,001
152	(596) Maintenance of Street Lighting and Signal Systems	1,540,575	820,734
153	(597) Maintenance of Meters	267,226	261,604
154	(598) Maintenance of Miscellaneous Distribution Plant	15,614,391	15,461,186
155	TOTAL Maintenance (Total of lines 146 thru 154)	55,899,033	54,681,146
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	84,481,610	79,603,945
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	912,009	1,267,077
161	(903) Customer Records and Collection Expenses	39,708,101	40,463,431
162	(904) Uncollectible Accounts	6,697,534	10,187,452
163	(905) Miscellaneous Customer Accounts Expenses	4,726,472	3,361,238
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	52,044,116	55,279,198

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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	9,949,139	9,913,514
169	(909) Informational and Instructional Expenses	2,258,174	2,896,148
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	12,207,313	12,809,662
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	52,489,752	43,430,089
182	(921) Office Supplies and Expenses	15,112,960	26,043,136
183	(Less) (922) Administrative Expenses Transferred-Credit	10,504,733	10,514,505
184	(923) Outside Services Employed	7,759,595	10,912,889
185	(924) Property Insurance	4,714,939	4,414,238
186	(925) Injuries and Damages	4,840,725	5,306,342
187	(926) Employee Pensions and Benefits	55,491,574	49,241,002
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	7,705,328	7,957,388
190	(929) (Less) Duplicate Charges-Cr.	2,065,837	1,983,633
191	(930.1) General Advertising Expenses	725,504	192,698
192	(930.2) Miscellaneous General Expenses	8,061,993	6,942,066
193	(931) Rents	3,881,853	3,957,345
194	TOTAL Operation (Enter Total of lines 181 thru 193)	148,213,653	145,899,055
195	Maintenance		
196	(935) Maintenance of General Plant	3,070,908	1,754,270
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	151,284,561	147,653,325
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,166,654,683	1,199,357,374

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PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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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.

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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	Avista Corp. - AVWP (was WWP)	SF	WSPP-1	NA	NA	NA
2	Barclays Bank PLC - BARC	SF	WSPP-1	NA	NA	NA
3	Baldock Solar	LU	Baldock	NA	NA	NA
4	Bellevue Solar	LU	Bellevue	NA	NA	NA
5	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
6	BP Energy Company	SF	PGE-11	NA	NA	NA
7	Brookfield Energy Marketing	SF	WSPP-1	NA	NA	NA
8	Burbank, City of	SF	WSPP-1	NA	NA	NA
9	California Independent System Operator	SF	CAISO	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	SF	WSPP-1	NA	NA	NA
13	Citigroup Energy	SF	WSPP-1	NA	NA	NA
14	Clatskanie County PUD	SF	WSPP-1	NA	NA	NA
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Constellation Energy Commodities	SF	PGE-11	NA	NA	NA
2	Covanta Marion	LU	QF83-118	NA	NA	NA
3	CP Energy Marketing (US)	SF	WSPP-1	NA	NA	NA
4	DB Energy Trading LLC	SF	WSPP-1	NA	NA	NA
5	Douglas County, PUD No. 1, Washington	LU	Wells	NA	NA	NA
6	Douglas County, PUD No. 1, Washington	LF	Wells	NA	NA	NA
7	Douglas County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
8	EDF Trading North America, LLC	SF	WSPP-1	NA	NA	NA
9	ESI Vansycle Partners, LP	LF	WSPP-1	NA	NA	NA
10	Eugene Water & Electric Board	LU	WSPP-1	10	10	10
11	Eugene Water & Electric Board	OS	ER94-717	NA	NA	NA
12	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
13	Eugene Water & Electric Board	EX	WSPP-1	NA	NA	NA
14	Exelon Generation Co.	SF	WSPP-1	NA	NA	NA
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Glendale, City of	SF	WSPP-1	NA	NA	NA
2	Grant County, PUD No. 2, Washington	LU	Wanapum	NA	NA	NA
3	Grant County, PUD No. 2, Washington	LU	Priest Rapids	NA	NA	NA
4	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
5	Iberdrola Renewables	SF	PGE-11	NA	NA	NA
6	Iberdrola Renewables	LU	PGE-11	NA	NA	NA
7	Idaho Power Company	SF	WSPP-1	NA	NA	NA
8	J. Aron Company	SF	PGE-11	NA	NA	NA
9	JP Morgan Ventures	SF	WSPP-1	NA	NA	NA
10	Load Balance Energy	OS	OATT	NA	NA	NA
11	Los Angeles Depart Water Power	SF	WSPP-1	NA	NA	NA
12	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
13	Merrill Lynch Commodities	SF	WSPP-1	NA	NA	NA
14	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
	Total					

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PURCHASED POWER (Account 555)
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1	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
2	NASDAQ OMX	SF	WSPP-1	NA	NA	NA
3	Nevada Power Company	SF	WSPP-1	NA	NA	NA
4	NextEra Energy Power Marketing, LLC	SF	WSPP-1	NA	NA	NA
5	NextEra Energy Power Marketing, LLC	LF	WSPP-1	NA	NA	NA
6	Noble Americas Gas & Power	SF	WSPP-1	NA	NA	NA
7	Northern California Power Agency	SF	WSPP-1	NA	NA	NA
8	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
9	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
10	Outback Solar	LU	Outback	NA	NA	NA
11	Pacific Gas & Electric Company	SF	WSPP-1	NA	NA	NA
12	PacifiCorp	RQ	PP&L 147	NA	NA	NA
13	PacifiCorp	SF	PGE-11	NA	NA	NA
14	PaTu Wind	LU	WSPP-1	NA	NA	NA
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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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	Portland, City of	LU	#2821	NA	NA	NA
2	Powerex	SF	PGE-11	NA	NA	NA
3	PPL Energy Plus	SF	PGE-11	NA	NA	NA
4	PRC - Coffin Butte Biomass	LU	PRC	NA	NA	NA
5	Public Utility District No. 1 of Clark	SF	WSPP-1	NA	NA	NA
6	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
7	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
8	Redding, City of	SF	WSPP-1	NA	NA	NA
9	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
10	San Diego Gas & Electric Company	SF	WSPP-1	NA	NA	NA
11	Seattle City Light	SF	WSPP-1	NA	NA	NA
12	Shell Energy	SF	WSPP-1	NA	NA	NA
13	Sierra Pacific	SF	WSPP-1	NA	NA	NA
14	Snohomish County, PUD No. 1, Washingt	SF	WSPP-1	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Southern California Edison	SF	PGE-11	NA	NA	NA
2	Spokane Energy, LLC	LF	PGE-82	150	150	144
3	Spokane Energy, LLC	EX	PGE-82	NA	NA	NA
4	Tacoma, City of	SF	WSPP-1	NA	NA	NA
5	Tenaska	SF	WSPP-1	NA	NA	NA
6	The Energy Authority	SF	WSPP-1	NA	NA	NA
7	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
8	TransAlta Energy Marketing	LF	PGE-11	NA	NA	NA
9	TransCanada Energy Marketing	SF	WSPP-1	NA	NA	NA
10	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
11	Warm Springs Power Enterprises	LU	WSPP-1	NA	NA	NA
12	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
13	Yamhill Solar	LU	Yamhill	NA	NA	NA
14	Lake Oswego Corporation	LU	201	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Country Village Estates	OS	201	NA	NA	NA
2	Douglas Pegar	OS	201	NA	NA	NA
3	Domaine Drouhin	OS	201	NA	NA	NA
4	Von Land Co	OS	201	NA	NA	NA
5	Minikahada Hydropower Co	OS	201	NA	NA	NA
6	Starbucks	OS	201	NA	NA	NA
7	SunWay LLC	OS	201	NA	NA	NA
8	Solar Feed-In	OS	205	NA	NA	NA
9	Tualatin Valley Water Dist	OS	201	NA	NA	NA
10	Oregon Heat	OS	203	NA	NA	NA
11	Load Curtailment Program			NA	NA	NA
12	Margin on Electric Financials			NA	NA	NA
13	PCA - 2002 Amortization			NA	NA	NA
14	Reserve Trading Credit Risk			NA	NA	NA
	Total					

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Green Power			NA	NA	NA
2	REC Retirement Expense			NA	NA	NA
3						
4	Non-cash exchanges					
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
(g)	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
220,084				3,601,554		3,601,554	1
1,200				-85,535		-85,535	2
1,927							3
1,879				178,369		178,369	4
421,036				6,886,551		6,886,551	5
3,600				52,280		52,280	6
4,400				168,700		168,700	7
782				15,721		15,721	8
166,713				1,177,931		1,177,931	9
1,368,330				31,727,999		31,727,999	10
123,727				2,533,301		2,533,301	11
26,662				292,515		292,515	12
589,200				5,029,425		5,029,425	13
3,817				56,840		56,840	14
12,654,253	457,195	457,647	19,930,200	258,481,846	114,808,545	393,220,591	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
32,681				489,549		489,549	1
86,336				5,815,902		5,815,902	2
295				6,425		6,425	3
148,605				2,303,056		2,303,056	4
842,716				7,992,329		7,992,329	5
260,836				7,651,457		7,651,457	6
30,231				692,911		692,911	7
92,761				1,428,321		1,428,321	8
69,200				4,172,960		4,172,960	9
			1,030,200			1,030,200	10
1,557							11
127,556				1,839,293		1,839,293	12
	26,100	26,140					13
800				21,920		21,920	14
12,654,253	457,195	457,647	19,930,200	258,481,846	114,808,545	393,220,591	

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.
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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)	
448				6,865		6,865	1
391,746							2
373,389				13,074,426		13,074,426	3
190,974				4,257,067		4,257,067	4
1,621,246				22,778,238		22,778,238	5
216,206				10,854,106		10,854,106	6
10,700				236,101		236,101	7
3,000				79,950		79,950	8
270,280				4,327,686		4,327,686	9
3,302				-12,028		-12,028	10
357				14,373		14,373	11
112,453				3,110,548		3,110,548	12
10,000				150,264		150,264	13
45				550		550	14
12,654,253	457,195	457,647	19,930,200	258,481,846	114,808,545	393,220,591	

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.
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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)	
45,098				684,969		684,969	1
11,200				273,750		273,750	2
11				176		176	3
1,540				36,340		36,340	4
337,353				7,028,051		7,028,051	5
3,200				55,100		55,100	6
1				10		10	7
-53,725				123,276		123,276	8
8,367				148,104		148,104	9
674				59,098		59,098	10
10,000				260,488		260,488	11
11,081				1,044,411		1,044,411	12
127,177				2,291,098		2,291,098	13
33,088				1,389,987		1,389,987	14
12,654,253	457,195	457,647	19,930,200	258,481,846	114,808,545	393,220,591	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	
100,357				4,359,843		4,359,843	1
41,039				1,380,726		1,380,726	2
113,571				3,096,381		3,096,381	3
11,856				599,560		599,560	4
34,686				452,328		452,328	5
79,938				1,445,090		1,445,090	6
4,495				107,360		107,360	7
35				610		610	8
6,349				172,057		172,057	9
281				7,925		7,925	10
127,578				2,685,694		2,685,694	11
592,803				4,320,054		4,320,054	12
345				6,845		6,845	13
33,688				491,493		491,493	14
12,654,253	457,195	457,647	19,930,200	258,481,846	114,808,545	393,220,591	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	
145,702				1,158,567		1,158,567	1
			18,900,000			18,900,000	2
	431,095	431,507					3
86,779				1,532,654		1,532,654	4
218				2,190		2,190	5
331,409				3,996,691		3,996,691	6
1,089,632				26,943,806		26,943,806	7
878,348				35,672,972		35,672,972	8
1,800				34,500		34,500	9
1,363				32,200		32,200	10
594,816				13,064,612		13,064,612	11
425				7,220		7,220	12
1,249				112,378		112,378	13
334				22,634		22,634	14
12,654,253	457,195	457,647	19,930,200	258,481,846	114,808,545	393,220,591	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
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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)	
44				1,658		1,658	1
232				16,189		16,189	2
77				4,779		4,779	3
185				12,222		12,222	4
372				23,820		23,820	5
29				1,561		1,561	6
2,855				166,524		166,524	7
4,911				220,910		220,910	8
82				5,015		5,015	9
228					8,263	8,263	10
					553,873	553,873	11
					106,076,382	106,076,382	12
					-113,955	-113,955	13
					54,476	54,476	14
12,654,253	457,195	457,647	19,930,200	258,481,846	114,808,545	393,220,591	

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
					8,091,120	8,091,120	1
					150,590	150,590	2
							3
					-12,204	-12,204	4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
12,654,253	457,195	457,647	19,930,200	258,481,846	114,808,545	393,220,591	

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

Non jurisdictional utilities.

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

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

Schedule Page: 326.1 Line No.: 11 Column: g

Represents net of energy generated at EWEB's Stone Creek facility within PGE's control area and energy delivered to EWEB.

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

Non jurisdictional utilities.

Schedule Page: 326.2 Line No.: 2 Column: c

Non jurisdictional utilities.

Schedule Page: 326.2 Line No.: 10 Column: a

Represents the value of energy delivered to the PGE control area from Electric 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 NextEra contract expires 12/31/15.

Schedule Page: 326.4 Line No.: 14 Column: c

Non jurisdictional utilities.

Schedule Page: 326.5 Line No.: 2 Column: b

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

Schedule Page: 326.5 Line No.: 8 Column: b

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

Schedule Page: 326.5 Line No.: 14 Column: b

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

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

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

Schedule Page: 326.6 Line No.: 2 Column: b

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

Schedule Page: 326.6 Line No.: 3 Column: b

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

Schedule Page: 326.6 Line No.: 4 Column: b

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

Schedule Page: 326.6 Line No.: 5 Column: b

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

Schedule Page: 326.6 Line No.: 6 Column: b

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

Schedule Page: 326.6 Line No.: 7 Column: b

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

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

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

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

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

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

In accordance with Schedule 203 tariff any excess credits will be transferred to Low Income Assistance Program.

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

Power purchased under Load Curtailment Program.

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

Margin on electric financial transactions.

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

Amortization of remaining balance of the 2002 Power Cost Adjustment.

Schedule Page: 326.6 Line No.: 14 Column: l

Reserve for price risk management credit risk.

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

Consists of expenses related to the purchase of RECs and developement of future renewable resources for PGE's Portfolio Options programs. Such expenses are fully offset by customer revenues.

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

Expense of annual REC retirement to meet RPS Compliance.

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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 Classification (d)
1	Avista Corp. Washington Water Power	Bonneville Power Administration	Balancing Authority of N. Calif	LFP
2	Avista Corp. Washington Water Power	Bonneville Power Administration	CAISO	LFP
3	Bonneville Power Administration	Bonneville Power Administration	CAISO	NF
4	Bonneville Power Administration	Bonneville Power Administration	Portland General Electric	FNO
5	Bonneville Power Administration	Bonneville Power Administration	Western Oregon Electric Coop	OLF
6	Bonneville Power Administration	Bonneville Power Administration	Other TVI Pumps	OLF
7	Bonneville Power Administration	Bonneville Power Administration	Canby People's Utility District	OLF
8	Bonneville Power Administration	Bonneville Power Administration	Columbia River PUD	OLF
9	Cargill Power Markets, LLC	CAISO	Bonneville Power Administration	SFP
10	Cargill Power Markets, LLC	Bonneville Power Administration	Balancing Authority of N. Calif	NF
11	Cargill Power Markets, LLC	Bonneville Power Administration	CAISO	NF
12	Cargill Power Markets, LLC	CAISO	Bonneville Power Administration	NF
13	Constellation Energy Commodities, Inc.	Bonneville Power Administration	CAISO	NF
14	Constellation New Energy, Inc	Bonneville Power Administration	Portland General Electric	NF
15	EDF Trading North America, LLC	Bonneville Power Administration	CAISO	NF
16	EDF Trading North America, LLC	CAISO	Bonneville Power Administration	NF
17	Iberdrola Renewables, Inc.	Bonneville Power Administration	Bonneville Power Administration	NF
18	Iberdrola Renewables, Inc.	Bonneville Power Administration	CAISO	NF
19	Iberdrola Renewables, Inc.	CAISO	Bonneville Power Administration	NF
20	JP Morgan Ventures Energy Corporation	Bonneville Power Administration	CAISO	NF
21	JP Morgan Ventures Energy Corporation	CAISO	Bonneville Power Administration	NF
22	Macquarie Energy, LLC	Balancing Authority of N. Calif	Bonneville Power Administration	NF
23	Macquarie Energy, LLC	CAISO	Bonneville Power Administration	NF
24	Macquarie Energy, LLC	Bonneville Power Administration	Balancing Authority of N. Calif	NF
25	Macquarie Energy, LLC	Bonneville Power Administration	CAISO	NF
26	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Balancing Authority of N. Calif	LFP
27	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	CAISO	LFP
28	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp	LFP
29	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Balancing Authority of N. Calif	NF
30	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	CAISO	NF
31	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp	NF
32	Morgan Stanley Capital Group Inc.	CAISO	Bonneville Power Administration	NF
33	Noble Americas Energy Solutions	Bonneville Power Administration	Portland General Electric	NF
34	Noble Americas Energy Solutions	Portland General Electric	Portland General Electric	NF
	TOTAL			

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

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

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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	Noble Americas Energy Solutions	Portland General Electric	Portland General Electric	NF
2	PacifiCorp	PacifiCorp	Portland General Electric	OLF
3	Powerex Corp.	Bonneville Power Administration	Balancing Authority of N. Calif	LFP
4	Powerex Corp.	Bonneville Power Administration	CAISO	LFP
5	Powerex Corp.	Bonneville Power Administration	PacifiCorp	LFP
6	Powerex Corp.	Bonneville Power Administration	Bonneville Power Administration	LFP
7	Powerex Corp.	Balancing Authority of N. Calif	Bonneville Power Administration	NF
8	Powerex Corp.	Bonneville Power Administration	Balancing Authority of N. Calif	NF
9	Powerex Corp.	Bonneville Power Administration	CAISO	NF
10	Powerex Corp.	Bonneville Power Administration	PacifiCorp	NF
11	Powerex Corp.	CAISO	Bonneville Power Administration	NF
12	Powerex Corp.	CAISO	Bonneville Power Administration	OS
13	Powerex Corp.	Bonneville Power Administration	CAISO	OS
14	Puget Sound Energy	Bonneville Power Administration	Bonneville Power Administration	LFP
15	Puget Sound Energy	Balancing Authority of N. Calif	Bonneville Power Administration	NF
16	Puget Sound Energy	Bonneville Power Administration	Balancing Authority of N. Calif	NF
17	Puget Sound Energy	Bonneville Power Administration	Bonneville Power Administration	NF
18	Puget Sound Energy	CAISO	Bonneville Power Administration	SFP
19	San Diego Gas & Electric Co.	Bonneville Power Administration	Balancing Authority of N. Calif	OLF
20	San Diego Gas & Electric Co.	Bonneville Power Administration	CAISO	OLF
21	Seattle City Light Marketing	Bonneville Power Administration	Balancing Authority of N. Calif	NF
22	Seattle City Light Marketing	Bonneville Power Administration	CAISO	NF
23	Shell Energy North America (US), L.P.	Bonneville Power Administration	Balancing Authority of N. Calif	LFP
24	Shell Energy North America (US), L.P.	Bonneville Power Administration	Bonneville Power Administration	LFP
25	Shell Energy North America (US), L.P.	Bonneville Power Administration	CAISO	LFP
26	Shell Energy North America (US), L.P.	Bonneville Power Administration	Balancing Authority of N. Calif	NF
27	Shell Energy North America (US), L.P.	Bonneville Power Administration	CAISO	NF
28	Shell Energy North America (US), L.P.	CAISO	Bonneville Power Administration	NF
29	Shell Energy North America (US), L.P.	CAISO	Bonneville Power Administration	OS
30	Southern California Edison	Bonneville Power Administration	CAISO	LFP
31	Southern California Edison	Bonneville Power Administration	CAISO	NF
32	Tacoma Power	Bonneville Power Administration	Balancing Authority of N. Calif	NF
33	The Energy Authority	Balancing Authority of N. Calif	Bonneville Power Administration	NF
34	The Energy Authority	Bonneville Power Administration	Balancing Authority of N. Calif	NF
	TOTAL			

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

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
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1	The Energy Authority	Bonneville Power Administration	CAISO	NF
2	The Energy Authority	CAISO	Bonneville Power Administration	NF
3	TransAlta Energy Marketing U.S. Inc.	Bonneville Power Administration	CAISO	NF
4	TransAlta Energy Marketing U.S. Inc.	CAISO	Bonneville Power Administration	NF
5	Turlock Irrigation District	Bonneville Power Administration	Balancing Authority of N. Calif	NF
6	Accrual			AD
7				
8				
9				
10				
11				
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29				
30				
31				
32				
33				
34				
	TOTAL			

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

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
8	John Day	Captain Jack		24,911	24,911	1
8	John Day	Malin 500		587,018	587,018	2
8	John Day	Malin 500		5,993	5,993	3
8	Various Subs	Various Subs	140	88,202	89,193	4
72	Various Subs	Various Subs		12,483	12,706	5
72	Various Subs	Various Subs		6,561	6,678	6
72	Various Subs	Various Subs		174,242	177,351	7
72	Various Subs	Various Subs		212,011	215,795	8
8	Malin 500	John Day		240	240	9
8	John Day	Captain Jack		25	25	10
8	John Day	Malin 501		135	135	11
8	John Day	Captain Jack		60	60	12
8	John Day	Malin 500		43,447	43,447	13
8	BPAT.PGE	Portland General Elc	127,052	70,269	76,474	14
8	John Day	Malin 500		852	852	15
8	Malin 500	John Day		175	175	16
8	John Day	Malin 501		250	250	17
8	KFalls Gen	John Day		50	50	18
8	Malin 500	John Day		560	560	19
8	John Day	Malin 500		25	25	20
8	Malin 500	John Day		33	33	21
8	Captain Jack	John Day		120	120	22
8	Malin 500	John Day		748	748	23
8	John Day	Captain Jack		430	430	24
8	John Day	Malin 500		9,349	9,349	25
8	John Day	Captain Jack		34,796	34,796	26
8	John Day	Malin 500		2,082	2,082	27
8	John Day	Malin 500		9,246	9,246	28
8	John Day	Captain Jack		16,435	16,435	29
8	John Day	Malin 500		35,148	35,148	30
8	John Day	Malin 501		492	492	31
8	Malin 500	John Day		1,045	1,045	32
8	BPAT.PGE	Portland General Elc	2,281,900	1,160,419	1,188,633	33
8	BPAT.PGE	Portland General Elc		20	20	34
			2,409,092	**5,120,656**	**5,161,606**	

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
8	PGE.INTERNAL	Portland General Elc		42,665	43,703	1
	John Day	Various Subs		2,731		2
8	John Day	Captain Jack		96,613	96,613	3
8	John Day	Malin 499		1,177,190	1,177,190	4
8	John Day	Malin 500		51	51	5
8	John Day	COBH		3,784	3,784	6
8	Captain Jack	John Day		6	6	7
8	John Day	Captain Jack		6,454	6,454	8
8	John Day	Malin 500		57,536	57,536	9
8	John Day	Malin 500		205	205	10
8	Malin 500	John Day		1,991	1,991	11
8	Malin 500	John Day		72	72	12
8	John Day	Malin 500		35	35	13
8	KFalls Gen	John Day		966	966	14
8	Captain Jack	John Day		279	279	15
8	John Day	Captain Jack		477	477	16
8	KFalls Gen	John Day		1,042	1,042	17
8	Malin 500	John Day		124,751	124,751	18
8	John Day	Captain Jack		810	810	19
8	John Day	Malin 501		33,844	33,844	20
8	John Day	Captain Jack		698	698	21
8	John Day	Malin 501		58	58	22
8	John Day	Captain Jack		448,943	448,943	23
8	John Day	COBH		532	532	24
8	John Day	Malin 500		475,804	475,804	25
8	John Day	Captain Jack		155	155	26
8	John Day	Malin 500		4,252	4,252	27
8	Malin 500	John Day		2,571	2,571	28
8	Malin 501	John Day		181	181	29
8	John Day	Malin 500		38,429	38,429	30
8	John Day	Malin 500		10,186	10,186	31
8	John Day	Captain Jack		10	10	32
8	Captain Jack	John Day		230	230	33
8	John Day	Captain Jack		6,613	6,613	34
			2,409,092	**5,120,656**	**5,161,606**	

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
8	John Day	Malin 500		9,174	9,174	1
8	Malin 500	John Day		848	848	2
8	John Day	Malin 500		53,523	53,523	3
8	Malin 500	John Day		18,092	18,092	4
8	John Day	Captain Jack		983	983	5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
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						26
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						28
						29
						30
						31
						32
						33
						34
			2,409,092	**5,120,656**	**5,161,606**	

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.
	26,175		26,175	1
	616,814		616,814	2
	7,082		7,082	3
61,658		23,544	85,202	4
	50,580		50,580	5
	11,179		11,179	6
	215,309		215,309	7
	47,267		47,267	8
	306		306	9
	23		23	10
	126		126	11
	56		56	12
	45,497		45,497	13
62,255			62,255	14
	1,352		1,352	15
	278		278	16
	290		290	17
	58		58	18
	650		650	19
	18		18	20
	24		24	21
	126		126	22
	787		787	23
	452		452	24
	9,836		9,836	25
	30,399		30,399	26
	1,819		1,819	27
	8,078		8,078	28
	22,047		22,047	29
	47,151		47,151	30
	660		660	31
	1,402		1,402	32
1,118,131			1,118,131	33
				34
1,242,044	**5,736,541**	**274,735**	**7,253,320**	

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

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
		247,235	247,235	2
	127,389		127,389	3
	1,552,185		1,552,185	4
	67		67	5
	4,989		4,989	6
	9		9	7
	9,346		9,346	8
	83,317		83,317	9
	297		297	10
	2,883		2,883	11
				12
				13
	642,989		642,989	14
	408		408	15
	697		697	16
	1,522		1,522	17
	102,814		102,814	18
	15,193		15,193	19
	634,807		634,807	20
	828		828	21
	69		69	22
	359,803		359,803	23
	426		426	24
	381,331		381,331	25
	177		177	26
	4,845		4,845	27
	2,929		2,929	28
				29
	544,418		544,418	30
	13,897		13,897	31
	19		19	32
	223		223	33
	6,411		6,411	34
1,242,044	**5,736,541**	**274,735**	**7,253,320**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
	8,894		8,894	1
	822		822	2
	64,040		64,040	3
	21,647		21,647	4
	1,009		1,009	5
		3,956	3,956	6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
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				26
				27
				28
				29
				30
				31
				32
				33
				34
1,242,044	**5,736,541**	**274,735**	**7,253,320**	

Schedule Page: 328 Line No.: 1 Column: d
Contract with Avista Corporation Washington Water Power Division expired 01/01/2013.

Schedule Page: 328 Line No.: 2 Column: d
Contract with Avista Corporation Washington Water Power Division expired 01/01/2013.

Schedule Page: 328 Line No.: 4 Column: m
Represents monthly facility usage charges.

Schedule Page: 328 Line No.: 5 Column: d
Contract with Bonneville Power Administration continues until terminated.

Schedule Page: 328 Line No.: 6 Column: d
Contract with Bonneville Power Administration continues until terminated.

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.: 26 Column: d
Contract with Morgan Stanley Capital Group Inc. expired 10/01/2012.

Schedule Page: 328 Line No.: 27 Column: d
Contract with Morgan Stanley Capital Group Inc. expired 10/01/2012.

Schedule Page: 328 Line No.: 28 Column: d
Contract with Morgan Stanley Capital Group Inc. expired 10/01/2012.

Schedule Page: 328.1 Line No.: 2 Column: d
Exchange agreement with Pacificorp.

Schedule Page: 328.1 Line No.: 2 Column: e
Exchange agreement with Pacificorp. No tariff applicable to exchange agreement.

Schedule Page: 328.1 Line No.: 2 Column: m
Represents monthly facility usage charges.

Schedule Page: 328.1 Line No.: 3 Column: d
Contract with Powerex Corp. expires 06/01/2013.

Schedule Page: 328.1 Line No.: 4 Column: d
Contract with Powerex Corp. expires 06/01/2013.

Schedule Page: 328.1 Line No.: 5 Column: d
Contract with Powerex Corp. expires 06/01/2013.

Schedule Page: 328.1 Line No.: 6 Column: d
Contract with Powerex Corp. expires 06/01/2013.

Schedule Page: 328.1 Line No.: 12 Column: d
Represents non-billed redirected MWHs of Powerex's LFP reservations.

Schedule Page: 328.1 Line No.: 13 Column: d
Represents non-billed redirected MWHs of Powerex's LFP reservations.

Schedule Page: 328.1 Line No.: 14 Column: d
Contract with Puget Sound Energy expires 01/01/2017.

Schedule Page: 328.1 Line No.: 19 Column: d
Contract with San Diego Gas & Electric expires 12/13/2013.

Schedule Page: 328.1 Line No.: 20 Column: d
Contract with San Diego Gas & Electric expires 12/13/2013.

Schedule Page: 328.1 Line No.: 23 Column: d
Contract with Shell Energy North America (US), L.P. expires 01/01/2022.

Schedule Page: 328.1 Line No.: 24 Column: d
Contract with Shell Energy North America (US), L.P. expires 01/01/2022.

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

Contract with Shell Energy North America (US), L.P. expires 01/01/2022.

Schedule Page: 328.1 Line No.: 29 Column: d

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

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

Contract with Southern California Edison expired 01/01/2013.

Schedule Page: 328.2 Line No.: 6 Column: d

Represents the difference between actual transmission revenue for the period as reflected on the individual line items within this schedule, and the accruals credited during the period to FERC Account 456.1, Revenues from Transmission of Electricity for Others.

Schedule Page: 328.2 Line No.: 6 Column: m

Represents the difference between actual transmission revenue for the period as reflected on the individual line items within this schedule, and the accruals credited during the period to FERC Account 456.1, Revenues from Transmission of Electricity for Others.

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

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
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22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	TRANSFER OF ENERGY Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp	NF	27,050	27,050		79,899		79,899
2	Bonneville Power Admin	LFP			54,354,364			54,354,364
3	Bonneville Power Admin	OS					13,033,548	13,033,548
4	Bonneville Power Admin	NF	277,853	277,853		653,662		653,662
5	BPA Amortization	FNS					146,073	146,073
6	Columbia River PUD	NF	9	9		3,948		3,948
7	Fale-Safe, Inc	OS					-1,434,289	-1,434,289
8	Idaho Power Company	NF	275	275		2,130		2,130
9	McMinnville Water & Lig	NF					8,739	8,739
10	Montana, State of	OS					1,547,030	1,547,030
11	Morgan Stanley	NF	55,200	55,200		103,776		103,776
12	Nevada Power Company	NF	100	100		337		337
13	Northwestern Corp	NF	27,119	27,119		122,863		122,863
14	PacifiCorp	OS					103,752	103,752
15	PacifiCorp	NF	352	352		1,033		1,033
16	Puget Sound Energy	NF	1,671	1,671		4,540		4,540
	TOTAL		389,629	389,629	54,354,364	972,188	13,404,853	68,731,405

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

The Bonneville Power Administration PTP Network contract expires on 12/31/2014. 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.: 9 Column: g

Represents Ancillary Services provided by McMinnville Water and Light.

Schedule Page: 332 Line No.: 10 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.: 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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,929,667
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	776,312
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,286,538
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Involuntary Severance	952,743
7	Directors Pension	58,329
8	Directors Fees and Expenses	976,335
9	Directors and Officers Expenses	1,390,560
10	Misc Admin R&D Expenses	
11	Misc Admin Expenses	246,455
12	Misc General Expenses Colstrip - PPL Montana	445,054
13		
14		
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46	TOTAL	8,061,993

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

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			21,547,511		21,547,511
2	Steam Production Plant	21,121,608	2,813,784			23,935,392
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	10,132,267	64			10,132,331
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	52,100,438	79,387			52,179,825
7	Transmission Plant	9,594,083	1,676			9,595,759
8	Distribution Plant	111,265,022	9,616			111,274,638
9	Regional Transmission and Market Operation					
10	General Plant	18,566,111	2,080			18,568,191
11	Common Plant-Electric					
12	TOTAL	222,779,529	2,906,607	21,547,511		247,233,647

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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							
13	Complete data will be						
14	provided in the 2016						
15	Form 1 (5 year						
16	interval).						
17							
18							
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Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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-NERC Reliability		199,061	199,061	
2	Docket No. RM06-16				
3					
4	FERC-NERC Reliability		171,350	171,350	
5	Docket No. RM06-22				
6					
7	OPUC-2012 Annual Power Cost Update Tariff		188,433	188,433	
8	Docket No. UE 228				
9					
10	OPUC-Investigation into Competitive Bidding		52,505	52,505	
11	Docket No. UM 1182				
12					
13	OPUC-RFP for Capacity&BaseLoad Energy Resorces		45,701	45,701	
14	Docket No. UM 1535				
15					
16	OPUC-PaTu Wind Farm, LLC Complaint		51,370	51,370	
17	Docket No. UM 1566				
18					
19	Trojan Rate Remand		31,478	31,478	
20	Docket No. UE 88				
21					
22	FERC matters less than $25,000		12,059	12,059	
23					
24	OPUC matters less than $25,000		373,649	373,649	
25					
26	Non Docs matters		421,348	421,348	
27					
28					
29					
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32					
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45					
46	TOTAL		1,546,954	1,546,954	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	199,061					1
							2
							3
	928	171,350					4
							5
							6
	928	188,433					7
							8
							9
	928	52,505					10
							11
							12
	928	45,701					13
							14
							15
	928	51,370					16
							17
							18
	928	31,478					19
							20
							21
	928	12,059					22
							23
	928	373,649					24
							25
	928	421,348					26
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							30
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		1,546,954					46

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

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A(1)	Electric R, D & D Performed Internally - Generation
2	A(1)(a)	Hydroelectric
3	A(1)(b)	Fossil-fuel Steam
4	A(1)(c)	Interanl Combustion or Gas Turbine
5	A(1)(e)	Unconventional Generation
6	A(2)	Electric R, D & D Performed Internally - Transmission
7	A(3)	Electric R, D & D Performed Internally - Distribution
8		
9	B(1)	Electric R, D & D Performed Externally
10		Research Support to the Electrical Research Council or EPRI
11		
12		
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26	Totals	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
7,744		930.2	7,744		2
75,027		930.2	75,027		3
31,472		930.2	31,472		4
460,268		930.2	460,268		5
39,834		930.2	39,834		6
70,887		930.2	70,887		7
					8
	91,081	930.2	91,081		9
					10
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685,232	91,081		776,313		26
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	24,364,011		
4	Transmission	3,406,337		
5	Regional Market			
6	Distribution	18,484,690		
7	Customer Accounts	25,002,935		
8	Customer Service and Informational	6,445,632		
9	Sales			
10	Administrative and General	39,805,520		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	117,509,125		
12	Maintenance			
13	Production	10,697,299		
14	Transmission	1,501,020		
15	Regional Market			
16	Distribution	19,322,055		
17	Administrative and General	803,096		
18	TOTAL Maintenance (Total of lines 13 thru 17)	32,323,470		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	35,061,310		
21	Transmission (Enter Total of lines 4 and 14)	4,907,357		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	37,806,745		
24	Customer Accounts (Transcribe from line 7)	25,002,935		
25	Customer Service and Informational (Transcribe from line 8)	6,445,632		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	40,608,616		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	149,832,595	12,666,258	162,498,853
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			

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)	149,832,595	12,666,258	162,498,853
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	62,592,852	4,236,750	66,829,602
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	62,592,852	4,236,750	66,829,602
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,142,663	3,474	1,146,137
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,142,663	3,474	1,146,137
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	1,632,498	265,844	1,898,342
79	Co-owner Shares of Generating Facilities	8,176,184	448,518	8,624,702
80	Other	4,558,792	3,193,060	7,751,852
81	Payroll Allocated	20,813,904	-20,813,904	
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	35,181,378	-16,906,482	18,274,896
96	TOTAL SALARIES AND WAGES	248,749,488		248,749,488

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

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	92,622	436,385	316,451	1,177,932
3	Net Sales (Account 447)	1,730,703	2,687,646	2,393,506	9,910,361
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	1,823,325	3,124,031	2,709,957	11,088,293

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	46,284	MW	15,043,644	5,684,728	Various	133,464
2	Reactive Supply and Voltage				2,409,092	Various	77,645
3	Regulation and Frequency Response				2,409,092	Various	180,812
4	Energy Imbalance	133	MWh	842	36,561	MWh	649,246
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	46,417		15,044,486	10,539,473		1,041,167

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

Scheduling, System Control and Dispatch	No of Units	Amount
MW Day	15,500	436
MW Hour	275,445	5,565
MW Month	124,891	4,147
MW Year	2,859,940	99,227
Sum of Peak Demand (KW)	2,408,952	24,089
	5,684,728	**133,464**

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

Reactive Supply and Voltage	No of Units	Amount
MW Month	140	5,376
Sum of Peak Demand (KW)	2,408,952	72,269
	2,409,092	**77,645**

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

Regulation and Frequency Response	No of Units	Amount
MW Month	140	12,185
Sum of Peak Demand (KW)	2,408,952	168,627
	2,409,092	**180,812**

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 due to the summation of amounts of dissimilar units of measure.

Schedule Page: 398 Line No.: 8 Column: e

Total is not meaningful due to the summation of amounts of dissimilar units of measure.

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

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,810	16	1800	3,267	170	1,062	13	4,227	34
2	February	4,507	27	1900	2,845	175	1,062	13	4,227	30
3	March	4,661	21	2000	3,146	17	1,062	13	4,227	
4	Total for Quarter 1	13,978			9,258	362	3,186	39	12,681	64
5	April	3,689	6	1000	2,604	174	1,062	13	4,227	18
6	May	3,653	2	800	2,432	167	1,062	13	4,227	
7	June	3,610	21	1900	2,513	197	1,062	13	4,227	9
8	Total for Quarter 2	10,952			7,549	538	3,186	39	12,681	27
9	July	4,337	11	1800	2,909	208	1,162	13	4,227	15
10	August	4,640	6	1600	3,176	221	1,162	13	4,227	228
11	September	4,056	7	1700	2,994	207	1,162	13	4,227	25
12	Total for Quarter 3	13,033			9,079	636	3,486	39	12,681	268
13	October	3,471	16	1900	2,335	175	1,162	13	4,227	50
14	November	3,959	16	1800	2,650	175	1,162	13	4,323	30
15	December	4,212	17	1800	3,152	180	1,162	13	4,323	57
16	Total for Quarter 4	11,642			8,137	530	3,486	39	12,873	137
17	Total Year to Date/Year	49,605			34,023	2,066	13,344	156	50,916	496

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	291	24	100			307			
2	February	291	18	2300			307			
3	March	302	7	1100			307			
4	Total for Quarter 1	884					921			
5	April	291	23	1800			307			
6	May	278	2	1700			307			
7	June	236	29	1200			307			
8	Total for Quarter 2	805					921			
9	July	257	21	1800			307			
10	August	294	18	400			307			
11	September	294	2	1100			307			
12	Total for Quarter 3	845					921			
13	October	292	20	1500			307			
14	November	295	19	500			307			
15	December	294	2	2300			307			
16	Total for Quarter 4	881					921			
17	Total Year to Date/Year	3,415					3,684			

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

Long Term Firm Point-to-Point Reservations: Q1

Reservation #	Customer	MW Granted Jan	MW Granted Feb	MW Granted Mar	Earliest Termination Date
432190	Portland General Electric Co.	100	100	100	01/01/2022
71324505	Powerex	165	165	165	06/01/2013
71324658	Avista Water and Power	100	100	100	01/01/2013
71472976	Shell Energy NA	200	200	200	01/01/2022
71915367	Powerex	97	97	97	01/01/2017
74566698	Portland General Electric Co.	100	100	100	01/01/2022
75731986	Puget Sound Energy Marketing	100	100	100	01/01/2017
76412778	Portland General Electric Co.	200	200	200	01/01/2017
	Total	**1,062**	**1,062**	**1,062**	

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

Other Long Term Service: Q1

Reservation #	Customer	MW Granted Jan	MW Granted Feb	MW Granted Mar	Earliest Termination Date
Grandfathered	SEMPRA (San Diego Gas & Electric)	13	13	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	MW Granted Jan	MW Granted Feb	MW Granted Mar
76468649	Portland General Electric Co.	2		
76468657	Portland General Electric Co.	200		
76468663	Portland General Electric Co.	500		
76468672	Portland General Electric Co.	25		
76468682	Portland General Electric Co.	3,300		
76469391	Portland General Electric Co.	200		
76468688	Portland General Electric Co.		25	25
76468694	Portland General Electric Co.		500	500
76468700	Portland General Electric Co.		200	200
76468710	Portland General Electric Co.		2	2
76487166	Portland General Electric Co.		200	200
76570946	Portland General Electric Co.		3,300	
76621444	Portland General Electric Co.			3,300
	Total	**4,227**	**4,227**	**4,227**

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 Reservations: Q2

Reservation #	Customer	MW Granted Apr	MW Granted May	MW Granted Jun	Earliest Termination Date
432190	Portland General Electric Co.	100	100	100	01/01/2022
71324505	Powerex	165	165	165	06/01/2013
71324658	Avista Water and Power	100	100	100	01/01/2013
71472976	Shell Energy NA	200	200	200	01/01/2022
71915367	Powerex	97	97	97	01/01/2017
74566698	Portland General Electric Co.	100	100	100	01/01/2022
75731986	Puget Sound Energy Marketing	100	100	100	01/01/2017
76412778	Portland General Electric Co.	200	200	200	01/01/2017
	Total	**1,062**	**1,062**	**1,062**	

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

Other Long Term Service: Q2

Reservation #	Customer	MW Granted Apr	MW Granted May	MW Granted Jun	Earliest Termination Date
Grandfathered	SEMPRA (San Diego Gas & Electric)	13	13	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	MW Granted Apr	MW Granted May	MW Granted Jun
76468688	Portland General Electric Co.	25	25	25
76468694	Portland General Electric Co.	500	500	500
76468700	Portland General Electric Co.	200	200	200
76468710	Portland General Electric Co.	2	2	2
76487166	Portland General Electric Co.	200	200	200
76745779	Portland General Electric Co.	3,300		
76855737	Portland General Electric Co.		3,300	
76951563	Portland General Electric Co.			3,300
	Total	**4,227**	**4,227**	**4,227**

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 Reservations: Q3

Reservation #	Customer	MW Granted Jul	MW Granted Aug	MW Granted Sep	Earliest Termination Date
432190	Portland General Electric Co.	100	100	100	01/01/2022
71324505	Powerex	165	165	165	06/01/2013
71324658	Avista Water and Power	100	100	100	01/01/2013
71472976	Shell Energy NA	200	200	200	01/01/2022
71915367	Powerex	97	97	97	01/01/2017
74382640	Portland General Electric Co.	100	100	100	07/01/2017
74566698	Portland General Electric Co.	100	100	100	01/01/2022
75731986	Puget Sound Energy Marketing	100	100	100	01/01/2017
76412778	Portland General Electric Co.	200	200	200	01/01/2017
	Total	**1,162**	**1,162**	**1,162**	

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

Other Long Term Service: Q3

Reservation #	Customer	MW Granted Jul	MW Granted Aug	MW Granted Sep	Earliest Termination Date
Grandfathered	SEMPRA (San Diego Gas & Electric)	13	13	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	MW Granted Jul	MW Granted Aug	MW Granted Sep
76468688	Portland General Electric Co.	25	25	25
76468694	Portland General Electric Co.	500	500	500
76468700	Portland General Electric Co.	200	200	200
76468710	Portland General Electric Co.	2	2	2
76487166	Portland General Electric Co.	200	200	200
77018848	Portland General Electric Co.	3,300		
77151581	Portland General Electric Co.		3,300	
77311686	Portland General Electric Co.			3,300
	Total	**4,227**	**4,227**	**4,227**

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 Reservations: Q4

Reservation #	Customer	MW Granted Oct	MW Granted Nov	MW Granted Dec	Earliest Termination Date
432190	Portland General Electric Co.	100	100	100	01/01/2022
71472976	Shell Energy NA	200	200	200	01/01/2022
71324505	Powerex	165	165	165	06/01/2013
71324658	Avista Water and Power	100	100	100	01/01/2013
71915367	Powerex	97	97	97	01/01/2017
74382640	Portland General Electric Co.	100	100	100	07/01/2017
74566698	Portland General Electric Co.	100	100	100	01/01/2022
75731986	Puget Sound Energy Marketing	100	100	100	01/01/2017
76412778	Portland General Electric Co.	200	200	200	01/01/2017
	Total	**1,162**	**1,162**	**1,162**	

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

Other Long Term Service: Q4

Reservation #	Customer	MW Granted Oct	MW Granted Nov	MW Granted Dec	Earliest Termination Date
Grandfathered	SEMPRA (San Diego Gas & Electric)	13	13	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	MW Granted Oct	MW Granted Nov	MW Granted Dec
76468688	Portland General Electric Co.	25	25	25
76468694	Portland General Electric Co.	500	500	500
76468700	Portland General Electric Co.	200	200	200
76468710	Portland General Electric Co.	2	2	2
76487166	Portland General Electric Co.	200	200	200
77384620	Portland General Electric Co.	3,300		
77492012	Portland General Electric Co.		3,300	
77511010	Puget Sound Energy Marketing		96	
77611394	Portland General Electric Co.			3,300
77615473	Puget Sound Energy Marketing			96
	Total	**4,227**	**4,323**	**4,323**

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

Colstrip
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 system during the calendar month

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

Long Term Firm Point-to-Point Reservations: Q1

Reservation #	Customer	MW Granted Jan	MW Granted Feb	MW Granted Mar	Earliest Termination Date
76059414	Portland General Electric Co.	307	307	307	07/01/2022

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

Colstrip
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 system during the calendar month

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

Long Term Firm Point-to-Point Reservations: Q2

Reservation #	Customer	MW Granted Apr	MW Granted May	MW Granted Jun	Earliest Termination Date
76059414	Portland General Electric Co.	307	307	307	07/01/2022

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

Colstrip
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 system during the calendar month

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

Long Term Firm Point-to-Point Reservations: Q3

Reservation #	Customer	MW Granted Jul	MW Granted Aug	MW Granted Sep	Earliest Termination Date
76059414	Portland General Electric Co.	307	307	307	07/01/2022

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

Colstrip
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 system during the calendar month

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

Long Term Firm Point-to-Point Reservations: Q4

Reservation #	Customer	MW Granted Oct	MW Granted Nov	MW Granted Dec	Earliest Termination Date
76059414	Portland General Electric Co.	307	307	307	07/01/2022

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

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	17,944,435
3	Steam	3,610,126			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	1,942,761			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,188,338
7	Other	4,006,534			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	9,559,421	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	24,148
10	Purchases	12,654,253	27	Total Energy Losses	1,015,351
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	22,172,272
12	Received	457,195			
13	Delivered	457,647			
14	Net Exchanges (Line 12 minus line 13)	-452			
15	Transmission For Other (Wheeling)				
16	Received	5,120,656			
17	Delivered	5,161,606			
18	Net Transmission for Other (Line 16 minus line 17)	-40,950			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	22,172,272			

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

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,995,863	182,933	3,426	16	18
30	February	1,797,018	177,518	3,239	29	19
31	March	1,891,756	196,281	3,146	21	20
32	April	1,803,911	311,463	2,883	5	8
33	May	1,809,784	332,472	2,895	14	18
34	June	1,636,168	228,368	2,744	21	18
35	July	2,000,472	477,241	3,105	11	18
36	August	2,010,277	378,836	3,597	16	17
37	September	1,709,587	254,379	3,193	7	18
38	October	1,738,751	227,267	2,818	23	19
39	November	1,816,072	239,832	3,068	27	19
40	December	2,003,563	224,474	3,356	18	18
41	TOTAL	22,213,222	3,231,064			

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

In addition to the generation form the Beaver, Port Westward and Coyote Springs steam generation plants, as shown on pages 403, Other Generation includes 1,124,396 megawatt hours of net wind energy as schedule and delivered by Bonneville Power Administration from PGE's Biglow Canyon Wind Project. Actual net wind generation from the Project to Bonneville Power Administration was 1,108,516 megawatt hours. This project was placed in service in three phases between December 2007 and August 2010. Key statistics include the following:

In-service Production cost at 12/31/2012: $920,116,373
Total installed capacity: 450 megawatts
Operations and Maintenance expenses for 2012: $18,525,073

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

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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	589	0
7	Plant Hours Connected to Load	5562	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	110	0
12	Net Generation, Exclusive of Plant Use - KWh	2603796000	1708157000
13	Cost of Plant: Land and Land Rights	1274078	832853
14	Structures and Improvements	155985238	103163607
15	Equipment Costs	545337678	356558026
16	Asset Retirement Costs	33978545	25189268
17	Total Cost	736575539	485743754
18	Cost per KW of Installed Capacity (line 17/5) Including	1146.9566	1163.6532
19	Production Expenses: Oper, Supv, & Engr	3435187	2096421
20	Fuel	55938280	35435628
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	3350254	2113125
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	4997436	3271731
27	Rents	0	0
28	Allowances	105984	105984
29	Maintenance Supervision and Engineering	589130	282934
30	Maintenance of Structures	3804	2628
31	Maintenance of Boiler (or reactor) Plant	1309374	852544
32	Maintenance of Electric Plant	17943703	11648733
33	Maintenance of Misc Steam (or Nuclear) Plant	269205	168233
34	Total Production Expenses	87942357	55977961
35	Expenses per Net KWh	0.0338	0.0328

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	1583256	12430	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8517	138690	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	32.933	133.308	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	39.104	128.857	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.296	22.121	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.024	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10357.600	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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			1901969000		
13	Cost of Plant: Land and Land Rights	0			3327818		
14	Structures and Improvements	0			115308214		
15	Equipment Costs	0			322188351		
16	Asset Retirement Costs	0			-285471		
17	Total Cost	0			440538912		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			1415.6135		
19	Production Expenses: Oper, Supv, & Engr	0			-173848		
20	Fuel	0			26975155		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			2008399		
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			2143311		
27	Rents	0			35391		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			-646864		
30	Maintenance of Structures	0			693913		
31	Maintenance of Boiler (or reactor) Plant	0			4726697		
32	Maintenance of Electric Plant	0			501137		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			640142		
34	Total Production Expenses	0			36903433		
35	Expenses per Net KWh	0.0000			0.0194		
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

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
421			425			275			6
356			4906			5381			7
0			0			0			8
533			415			270			9
0			0			0			10
52			21			26			11
31459000			1727020000			1123659000			12
0			0			0			13
31384600			40952016			10792313			14
174219740			219080628			172953820			15
42315			226391			112544			16
205646655			260259035			183858677			17
336.7392			538.5041			690.1602			18
250838			579440			1218997			19
7316619			45773570			30445224			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
1900153			1504557			530971			25
2119838			1579073			707925			26
175234			33682			69914			27
0			1728			0			28
774532			14607			21571			29
35352			57844			2046			30
0			0			0			31
3309778			5876023			6983994			32
54564			41083			29290			33
15936908			55461607			40009932			34
0.5066			0.0321			0.0356			35
Gas	Oil		Gas	Oil		Gas	Oil		36
Mcfs	Barrels		Mcfs	Barrels		Mcfs	Barrels		37
330511	32	0	12031467	0	0	8570449	0	0	38
1019000	138690	0	1019000	138690	0	1019000	138690	0	39
2.943	0.000	0.000	2.998	0.000	0.000	2.605	0.000	0.000	40
19.180	105.184	0.000	11.009	0.000	0.000	9.907	0.000	0.000	41
18.816	18.092	0.000	10.800	0.000	0.000	9.719	0.000	0.000	42
0.202	0.000	0.000	0.077	0.000	0.000	0.076	0.000	0.000	43
10709.600	0.000	0.000	7101.500	0.000	0.000	7775.000	0.000	0.000	44

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

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			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% interest) and operator of the Boardman Plant. The other owners are Idaho Power Company (10% interest), Power Resources Cooperative (10% interest), and BA Leasing BSC, LLC (15% interest). Reported here are 100% 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% share. Reported here are respondent's share of cost of plant, net generation and production expenses. 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 Line No.: 28 Column: b

Represents PGE only SO2 Allowance Expense reported in FERC Account 509 Allowances

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 respondent's 20 percent share of installed capacity, cost of plant, net generation and production expenses.

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 operation purposes

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

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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;Outdoor
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	47
7	Plant Hours Connect to Load	0	5,441
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	46
10	(b) Under the Most Adverse Oper Conditions	0	5
11	Average Number of Employees	0	44
12	Net Generation, Exclusive of Plant Use - Kwh	0	166,808,000
13	Cost of Plant		
14	Land and Land Rights	0	33,434
15	Structures and Improvements	0	6,479,397
16	Reservoirs, Dams, and Waterways	0	24,223,755
17	Equipment Costs	0	9,136,700
18	Roads, Railroads, and Bridges	0	1,976,298
19	Asset Retirement Costs	0	76
20	TOTAL cost (Total of 14 thru 19)	0	41,849,660
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	1,137.2190
22	Production Expenses		
23	Operation Supervision and Engineering	0	92,736
24	Water for Power	0	60,882
25	Hydraulic Expenses	0	530,988
26	Electric Expenses	0	181,526
27	Misc Hydraulic Power Generation Expenses	0	845,407
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	527,483
30	Maintenance of Structures	0	1,374
31	Maintenance of Reservoirs, Dams, and Waterways	0	234,250
32	Maintenance of Electric Plant	0	245,097
33	Maintenance of Misc Hydraulic Plant	0	689,380
34	Total Production Expenses (total 23 thru 33)	0	3,409,123
35	Expenses per net KWh	0.0000	0.0204

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

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2030 Plant Name: Pelton (b)	FERC Licensed Project No. 2030 Plant Name: Pelton (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	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	73.20
6	Net Peak Demand on Plant-Megawatts (60 minutes)	106	0
7	Plant Hours Connect to Load	7,697	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	110	0
10	(b) Under the Most Adverse Oper Conditions	60	0
11	Average Number of Employees	10	0
12	Net Generation, Exclusive of Plant Use - Kwh	455,649,000	303,781,000
13	Cost of Plant		
14	Land and Land Rights	3,672,025	2,448,139
15	Structures and Improvements	8,411,277	5,642,428
16	Reservoirs, Dams, and Waterways	15,061,416	10,223,106
17	Equipment Costs	9,522,571	6,376,915
18	Roads, Railroads, and Bridges	3,219,852	2,151,533
19	Asset Retirement Costs	42	42
20	TOTAL cost (Total of 14 thru 19)	39,887,183	26,842,163
21	Cost per KW of Installed Capacity (line 20 / 5)	363.2712	366.6962
22	Production Expenses		
23	Operation Supervision and Engineering	218,166	134,281
24	Water for Power	168,010	86,253
25	Hydraulic Expenses	1,021,455	360,461
26	Electric Expenses	192,272	123,005
27	Misc Hydraulic Power Generation Expenses	695,637	371,219
28	Rents	28,514	11,903
29	Maintenance Supervision and Engineering	85,980	25,705
30	Maintenance of Structures	2,023	2,023
31	Maintenance of Reservoirs, Dams, and Waterways	13,324	13,324
32	Maintenance of Electric Plant	243,780	88,280
33	Maintenance of Misc Hydraulic Plant	163,202	70,924
34	Total Production Expenses (total 23 thru 33)	2,832,363	1,287,378
35	Expenses per net KWh	0.0062	0.0042

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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. 2195 Plant Name: Oak Grove (f)	Line No.
Run-of-River	Run-of-River	Run-of-River;Stor	1
Outdoor	Conventional	Conventional	2
1958	1911	1924	3
1958	1952	1931	4
40.80	18.90	51.00	5
57	28	52	6
8,764	8,784	8,770	7
			8
58	25	44	9
7	4	19	10
0	0	7	11
250,907,000	117,079,000	275,313,000	12
			13
377,100	86,408	9,457	14
8,260,817	2,753,594	5,650,262	15
22,104,599	52,789,060	19,468,571	16
8,290,744	8,214,880	8,903,971	17
1,662,877	458,019	2,322,130	18
5	54	1,769	19
40,696,142	64,302,015	36,356,160	20
997.4545	3,402.2230	712.8659	21
			22
42,485	19,089	42,665	23
47,847	39,593	63,604	24
421,550	33,937	590,850	25
182,974	177,856	214,694	26
143,395	119,463	279,600	27
7,307	0	142,866	28
45,777	21,513	21,371	29
0	256	193	30
46,101	19,113	389,653	31
105,028	108,053	31,173	32
201,585	146,114	115,869	33
1,244,049	684,987	1,892,538	34
0.0050	0.0059	0.0069	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
Conventional	Conventional	Conventional	2
1964	1964	1895	3
1964	1964	1953	4
277.20	184.80	15.40	5
300	0	16	6
8,023	0	8,753	7
			8
353	0	18	9
192	0	7	10
39	0	1	11
1,063,706,000	709,173,000	119,700,000	12
			13
3,726,481	2,521,011	572,077	14
14,254,722	9,699,245	9,437,850	15
158,866,028	103,758,408	23,381,332	16
23,803,555	15,849,341	13,586,483	17
1,709,329	1,192,103	0	18
106	106	2,224	19
202,360,221	133,020,214	46,979,966	20
730.0152	719.8064	3,050.6471	21
			22
226,566	157,932	13,122	23
277,985	211,092	32,784	24
2,584,333	2,043,519	73,004	25
185,583	128,910	145,571	26
1,074,511	809,078	126,259	27
62,101	48,510	0	28
242,852	193,537	10,539	29
21,465	21,465	48,818	30
87,461	87,461	76,730	31
500,607	373,380	75,918	32
342,185	266,686	78,923	33
5,605,649	4,341,570	681,668	34
0.0053	0.0061	0.0057	35

Schedule Page: 406.1 Line No.: -2 Column: b

Respondent is the principal owner (66.67% 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% 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% share. Details reported on Page 406.1, column (b). Reported here are respondent's 66.67% share of cost of plant, net generation and production expenses.

Schedule Page: 406.1 Line No.: -2 Column: d

Respondent is the principal owner (66.67% 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% 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% share. Details reported on Page 407.1, column (d). Reported here are respondent's 66.67% share of cost of plant, net generation and production expenses.

Schedule Page: 406.1 Line No.: 19 Column: b

Represents PGE's ASC 410-20 Asset Retirement Cost (ARC)

Schedule Page: 406.1 Line No.: 19 Column: d

Represents PGE's ASC 410-20 Asset Retirement Cost (ARC)

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

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

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

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Maclaren	1999	0.50	0.4	6	104,631
2	Oregon Military Dept/A.F.R.C	2001	1.60	1.6	24	164,147
3	US Bank Corp Columbia Center	2001	6.40	6.2	74	488,058
4	Providence Business Center	2004	2.00	1.8	17	385,944
5	Portland State University	2004	2.80	2.8	45	261,732
6	Oregon Military Joint Forces HQ	2005	1.60	1.6	26	191,439
7	Stimson Lumber	2005	0.57	0.5	9	159,546
8	FORTIX (ViaWest)	2005	1.00	0.9	6	226,466
9	Skyline	2005	2.00	1.8	22	201,526
10	Tri-Quint	2005	0.60	0.5	8	109,968
11	NCCWC- Filter Plant	2005	2.00	1.8	38	122,958
12	PCC Structurals	2005	1.00	0.9	11	113,874
13	Providence Portland Medical Center	2005	6.00	5.4	88	256,701
14	Salem Hospital	2006	4.00	3.6	74	188,494
15	Sunrise Water Authority Pump Station	2006	1.25	1.1	18	88,272
16	Providence Newberg Hospital	2006	1.50	1.4	24	156,833
17	Sungard DSG	2006	2.00	1.8	26	331,845
18	Kaiser Sunnyside Hospital	2007	4.50	4.0	85	352,752
19	Newberg Waste Water Treatment Plant	2008	2.00	1.8	32	154,458
20	Xerox Corp	2007	4.00	3.6	58	380,259
21	Newberg Water Treatment Plant	2007	1.00	0.9	16	78,159
22	MEMC (Solaicx)	2008	1.00	0.9	15	62,963
23	Solar World	2008	3.00	2.7	39	219,984
24	Oregon Dept of Admin Serv - Data Center	2010	2.00	1.8	23	277,254
25	Sanyo	2010	1.00	0.9	11	43,144
26	Sysco Foods	2010	2.00	1.8	26	184,781
27	Clackamas Intertie 2	2012	0.60	0.5		60,701
28	Dawson Creek	2012	0.80	0.7	4	95,955
29	Kaiser Westside Hospital	2012	4.00	3.6	23	
30	North Plains Pump Station	2012	0.80	0.7	3	53,672
31	Oak Lodge Sanitary District	2012	2.00	1.8	10	229,144
32	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.50	1.4	22	284,255
33	Oregon State Hospital	2012	4.00	3.6	62	172,879
34	Portland Service Center	2012	0.50	0.5	8	322,698
35	Sandy Highschool	2012	1.25	1.1	19	179,413
36	TATA Communications - Hillsboro	2012	4.50	3.3	39	299,704
37	Tri-City Wastewater Treatment Plant	2012	2.50	2.3	15	161,755
38	Total					7,166,364
39						
40						
41						
42						
43						
44						
45						
46						

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

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
209,263			4,198	diesel-low s	1,779	1
102,592		11,540	4,903	diesel-low s or gas	2,587	2
76,259		33,984	25,241	diesel-low s	2,439	3
192,972			7,191	diesel-low s	2,293	4
93,476		14,556	74,638	diesel-low s	2,599	5
119,650		4,771	9,546	diesel-low s	2,524	6
282,382		1,560	4,604	diesel-low s	2,625	7
226,466		20,117	53,428	diesel-low s	2,472	8
100,763		5,783	2,345	diesel-low s	2,051	9
183,279		2,978	1,806	diesel-low s	2,664	10
61,479		7,298	6,058	diesel-low s	2,632	11
113,874		2,423	3,970	diesel-low s	2,471	12
42,784		42,298	39,885	diesel-low s	2,565	13
47,124		20,373	9,709	diesel-low s	2,553	14
70,617			4,170	diesel-low s	2,207	15
104,555		4,494	11,990	diesel-low s	2,675	16
165,922		4,607	6,205	diesel-low s	2,123	17
78,389		32,077	-495	diesel-low s	2,546	18
77,229		8,140		diesel-low s	2,911	19
95,065		10,596	12,142	diesel-low s	2,553	20
78,159		4,125	4,080	diesel-low s	2,911	21
62,963		2,824	2,789	diesel-low s	2,668	22
73,328		12,235	37,192	diesel-low s	2,569	23
138,627		8,482	4,720	diesel-low s	2,524	24
43,144		3,755	8,876	diesel-low s	2,682	25
92,391			8,748	diesel-low s	1,614	26
101,168			5,334	diesel-low s		27
119,943		6,412	3,799	diesel-low s	2,855	28
			5,291	diesel-low s	2,493	29
67,090				diesel-low s	3,213	30
114,572			1,849	diesel-low s	2,493	31
189,503		4,141	14,074	diesel-low s	2,689	32
43,220			21,455	diesel-low s	1,833	33
645,396			2,948	diesel-low s		34
143,530		4,315	10,029	diesel-low s	2,489	35
66,601			26,535	diesel-low s	1,571	36
64,702		7,591	8,337	diesel-low s	2,711	37
		281,475	447,590			38
						39
						40
						41
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						43
						44
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						46

Schedule Page: 410 Line No.: 29 Column: f

The capital balance $412,971 for Kaiser Westside was classified to a non production account in error and therefore is not recorded as production on Line 29. The costs will be reclassified to the proper capital production account in 2013.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (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	178.50		1
4	JOHN DAY	GRIZZLY '1'	500.00	500.00				1
5	JOHN DAY	GRIZZLY '2'	500.00	500.00				1
6	MISCELLANEOUS	MISCELLANEOUS						
7	BOARDMAN	BPA SLATT	500.00	500.00	ST. TOWER	17.83		1
8	COYOTE SPRINGS	BPA SLATT	500.00	500.00				2
9	COLSTRIP PROJECT:							
10	COLSTRIP SWYD.	BROADVIEW 'A'	500.00	500.00	ST. TOWER		112.30	1
11	COLSTRIP SWYD.	BROADVIEW 'B'	500.00	500.00	ST. TOWER		115.80	1
12	BROADVIEW SWYD.	TOWNSEND 'A'	500.00	500.00	ST. TOWER		133.40	1
13	BROADVIEW SWYD.	TOWNSEND 'B'	500.00	500.00	ST. TOWER		133.40	1
14	Colstrip Project Costs	Project Lines						
15	Tot 500KV Line Expenses							
16								
17	BIGLOW CANYON WF	JOHN DAY	230.00	230.00				1
18	PELTON 230KV PROJECT							
19	PELTON	ROUND BUTTE	230.00	230.00	H-WOOD	7.87		1
20								
21	NON PROJECT 230KV:							
22	BETHEL	ROUND BUTTE	230.00	230.00	H-WOOD	55.19		1
23			230.00	230.00	ST. TOWER	44.85		1
24	ROUND BUTTE	BPA REDMOND	230.00	230.00	H-WOOD	23.58		1
25	BETHEL	BPA TIE (SANTIAM)	230.00	230.00	H-WOOD	3.64		1
26	BETHEL	McLOUGHLIN	230.00	230.00	H-WOOD	35.57		1
27	CARVER	GRESHAM	230.00	230.00	H-WOOD	7.17		1
28	McLOUGHLIN	CARVER	230.00	230.00	H-WOOD	4.95		1
29	McLOUGHLIN	CARVER	230.00	230.00	ST. MONOP	4.88		1
30	BPA KEELER	ST. MARY'S W.	230.00	230.00	H-WOOD	2.89		1
31			230.00	230.00	ST. TOWER	3.78		2
32	BLUE LAKE	TROUTDALE BPA	230.00	230.00	H-WOOD	0.84		1
33			230.00	230.00	ST. MONOP	0.58		1
34	PEARL BPA	SHERWOOD	230.00	230.00	ST. TOWER		4.72	2
35			230.00	230.00	ST. TOWER	0.16		1
36					TOTAL	592.17	536.65	60

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	GRESHAM	LINNEMAN	230.00	230.00	ST. TOWER	0.31		1
2	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER	11.51		1
3			230.00	230.00	H-TOWER	0.60		1
4	NON PROJECT 230KV							
5	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER		4.40	2
6	ST. MARY'S W.	MURRAYHILL	230.00	230.00	ST. TOWER	5.92		1
7	HORIZON	KEELER BPA	230.00	230.00	ST. MONOP	1.47		1
8	MURRAYHILL	SHERWOOD	230.00	230.00	ST. TOWER	5.68		2
9	PORT WESTWARD	TROJAN	230.00	230.00	ST. MONOP	18.78		1
10			230.00	230.00	ST. MONOP	9.39		1
11	TROJAN	ST. MARY'S W.	230.00	230.00	H-WOOD	0.10		1
12			230.00	230.00	ST. TOWER	3.86		2
13			230.00	230.00	ST. TOWER	4.80		1
14			230.00	230.00	ST. TOWER	32.68		2
15	TROJAN	RIVERGATE	230.00	230.00	ST. TOWER		32.20	2
16			230.00	230.00	ST. TOWER	2.88		2
17	Tot Nonproj 230kv Costs							
18	GRESHAM	TROUTDALE BPA	230.00	230.00	ST. TOWER		0.43	1
19	BOARDMAN	PPL DALREED	230.00	230.00	H-WOOD	16.76		1
20	Tot 230KV LINE EXPENSES							
21								
22	PROJECT 115 KV LINES							
23	FARADAY	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		1
24	NORTH FORK	FARADAY	115.00	115.00	H-WOOD	2.79		1
25	OAK GROVE	FARADAY	115.00	115.00	DC LATTICE	18.68		2
26	OAK GROVE	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		2
27			115.00	115.00	DC LATTICE	18.68		2
28	Tot 115KV LINE EXPENSES							
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	592.17	536.65	60

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	15,581,384	15,856,811					3
		148,862	148,862					4
		148,862	148,862					5
	5,904		5,904					6
1480MCMACSR		4,620,708	4,620,708					7
		3,624,934	3,624,934					8
								9
								10
								11
								12
								13
	1,194,326	43,101,062	44,295,388					14
				189,240	144,317	1,024,964	1,358,521	15
								16
		3,040,852	3,040,852					17
								18
795MCMACSR	7,579	298,654	306,233					19
								20
								21
1272MCMACSR								22
1272MCMACSR								23
795MCMACSR								24
795MCMACSR								25
1272MCMACSR								26
1272MCMAAC								27
1272MCMAAC								28
1272MCMACSS								29
1590MCMACSRTW								30
1590MCMACSRTW								31
1780MCMACSR								32
								33
2388MCMAACTW								34
2388MCMAACTW								35
	11,235,588	141,684,930	152,920,518	522,067	398,135	1,037,433	1,957,635	36

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

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272MCMAAC								1
1272MCMAAC								2
1780MCMACSR								3
								4
1272MCMAAC								5
1272MCMAAC								6
1272MCMACSS								7
1272MCMAAC								8
2156MCMACSS								9
2156MCMACSS								10
1272MCMAAC								11
1272MCMAAC								12
1590MCMAAC								13
1590MCMAAC								14
1590MCMAAC								15
1272MCMACSR								16
	9,546,379	65,618,754	75,165,133					17
954KCMACSR								18
795KCMAAC		973,248	973,248					19
				321,466	245,154	4,828	571,448	20
								21
								22
795KCMACSR		871,841	871,841					23
556KCMACSR	120,248	621,351	741,599					24
250CU	12,477	503,937	516,414					25
795KCMACSR								26
250CU	22,295	884,661	906,956					27
				11,361	8,664	7,641	27,666	28
								29
								30
								31
								32
								33
								34
								35
	11,235,588	141,684,930	152,920,518	522,067	398,135	1,037,433	1,957,635	36

Schedule Page: 422 Line No.: 2 Column: a

Jointly owned with BA Leasing BSC, LLC. Total length is indicated. Costs represent respondent's share.

Schedule Page: 422 Line No.: 3 Column: a

Jointly owned with BA Leasing BSC, LLC. Total length is indicated. Costs represent respondent's share.

Schedule Page: 422 Line No.: 4 Column: a

Portland General Electric made payment in the form of Contribution in Aid of Construction (CIAC) in 2011 to Bonneville Power Administration (BPA) in support of increased line capacity as part of the 500-KV California Oregon Intertie. BPA installed higher capacity conductor on this line.PGE has certain capacity responsibilities in conjunction with the 500-KV California Oregon Intertie. PGE recorded the CIAC to FERC account 356 Transmission Overhead Conductors and Devices.Wire mileage not reported as BPA is owner/operator of this section of Transmission Line.

Schedule Page: 422 Line No.: 5 Column: a

Portland General Electric made payment in the form of Contribution in Aid of Construction (CIAC) in 2011 to Bonneville Power Administration (BPA) in support of increased line capacity as part of the 500-KV California Oregon Intertie. BPA installed higher capactiy conductor on this line. PGE has certain capactiy responsibilities in conjunction with the 500-KV California Oregon Intertie. PGE recorded the CIAC to FERC account 356 Transmission Overhead Conductors and Devices. Wire Milege is not reported here as BPA is owner/operator of this portion of the Transmission Line.

Schedule Page: 422 Line No.: 7 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.: 8 Column: a

Portland General Electric made payment in the form of Contribution in Aid of Construction (CIAC)in 1995 to Bonneville Power Administration. PGE recorded these costs to FERC accounts 354 Transmission Towers and Fixtures, 356 Transmission Overhead Conductors and Devices. Wire Mileage is not reported here as BPA is owner/opertor of these Tranmssion Lines.

Schedule Page: 422 Line No.: 9 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.: 15 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.: 17 Column: a

Portland General Electric made payment in the form of Contribution in Aid of Construction (CIAC) in 2007 to Bonneville Power Administration. PGE recorded the CIAC to FERC accounts 355 Transmission Poles and Fixtures, 356 Transmission Overhead Conductors and Devices. Wire mileage is not reported here as BPA is owner/operator of these transmission lines.

Schedule Page: 422 Line No.: 19 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.: 34 Column: a

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

Schedule Page: 422.1 Line No.: 18 Column: a

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

Schedule Page: 422.1 Line No.: 19 Column: a

Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing BSC, LLC. Total length is indicated. Costs are respondent's share.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Horizon Substation	Keeler Substation, BPA	1.47	ST. MONOP	18.00	1	1
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
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38							
39							
40							
41							
42							
43							
44	TOTAL		1.47		18.00	1	1

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

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
1272	MCMACSS		230		1,384,167	1,384,166		2,768,333	1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
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									39
									40
									41
									42
									43
					1,384,167	1,384,166		2,768,333	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	10 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	Dayton, near Dayton , OR	Distrib./unattended	115.00	57.00	13.00
29	Dayton, near Dayton , OR	Distrib./unattended	57.00	13.00	
30	Delaware, Portland, OR	Distrib./unattended	115.00	13.00	
31	Delaware, Portland, OR	Distrib./unattended	115.00	11.00	4.16
32	Denny, Beaverton, OR	Distrib./unattended	115.00	13.00	
33	Dilley, near Forest Grove, OR	Distrib./unattended	57.00	13.00	
34	Dunn's Corner, near Sandy,OR	Distrib./unattended	57.00	13.00	
35	Durham, Tigard , OR	Distrib./unattended	115.00	13.00	
36	E., East Yard, Portland, OR	Distrib./unattended	115.00	13.00	
37	E., East Yard, Portland, OR	Distrib./unattended	115.00	11.00	
38	E., West Yard, Portland, OR	Distrib./unattended	115.00	13.00	
39	E., West Yard, Portland, OR	Distrib./unattended	115.00	11.00	
40	Eagle Creek, Eagle Creek, OR	Distrib./unattended	57.00	13.00	

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	Eastport, Portland, OR	Distrib./unattended	115.00	13.00	
2	Elma, near Salem, OR	Distrib./unattended	57.00	13.00	
3	Estacada, Estacada, OR	Distrib./unattended	57.00	12.50	
4	Fairmount, Salem, OR	Distrib./unattended	115.00	13.00	
5	Fairview, Fairview, OR	Distrib./unattended	115.00	13.00	
6	Forest Grove BPA, Forest Grove, OR	Distrib./unattended	115.00		
7	Garden Home, near Portland, OR	Distrib./unattended	115.00	13.00	
8	Glencoe, Portland, OR	Distrib./unattended	115.00	13.00	
9	Glencullen, Portland, OR	Distrib./unattended	115.00	13.00	
10	Glendoveer, near Portland, OR	Distrib./unattended	115.00	13.00	
11	Glisan, Gresham, OR	Distrib./Unattended	115.00	13.00	
12	Grand Ronde, Grand Ronde, OR	Distrib./unattended	115.00	57.00	13.00
13	Grand Ronde, Grand Ronde, OR	Distrib./unattended	115.00	13.00	
14	Harborton, near Portland, OR	Distrib./unattended	115.00	13.00	
15	Harmony, near Milwaukie, OR	Distrib./unattended	115.00	13.00	
16	Harrison Sub, Portland, OR	Distrib./unattended	115.00	13.00	
17	Harrison Sub, Portland, OR	Distrib./unattended	57.00	11.00	4.16
18	Hayden Island, near Portland, OR	Distrib./unattended	115.00	13.00	
19	Hemlock, Portland, Or	Distrib./unattended	115.00	13.00	
20	Hillcrest, Salem , OR	Distrib./unattended	115.00	13.00	
21	Hillsboro, Hillsboro , OR	Distrib./unattended	57.00	13.00	
22	Hogan North, Gresham, OR	Distrib./unattended	115.00	13.00	
23	Hogan South, Gresham, OR	Distrib./unattended	115.00	57.00	13.00
24	Hogan South, Gresham, OR	Distrib./unattended	115.00	13.00	
25	Holgate, Portland, OR	Distrib./unattended	57.00	13.00	
26	Huber, near Beaverton, OR	Distrib./unattended	115.00	13.00	
27	Indian, near Salem, OR	Distrib./unattended	115.00	13.00	
28	Island, near Milwaukie, OR	Distrib./unattended	115.00	13.00	
29	Jennings Lodge, Jennings Lodge, OR	Distrib./unattended	115.00	13.00	
30	Kelley Point, Portland, OR	Distrib./unattended	115.00	13.00	
31	Kelly Butte, Portland, OR	Distrib./unattended	115.00	13.00	
32	King City, near King City, OR	Distrib./unattended	115.00	13.00	
33	Leland, Oregon City, OR	Distrib./unattended	57.00	13.00	
34	Lents, near Portland, OR	Distrib./unattended	115.00	13.00	
35	Lents, near Portland, OR	Distrib./unattended	57.00	11.00	
36	Liberty, Salem, OR	Distrib./unattended	115.00	13.00	
37	Main, Hillsboro, OR	Distrib./unattended	57.00	13.00	
38	Market Street, Salem, OR	Distrib./unattended	115.00	12.50	
39	McClain, Salem, OR	Distrib./unattended	57.00	13.00	
40	Meridian, near Tualatin, OR	Distrib./unattended	115.00	13.00	

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Salem-PGE, near Salem, OR	Distrib./unattended	57.00	13.00	
2	Sandy, Sandy, OR	Distrib./unattended	57.00	13.00	
3	Scappoose, Scappoose, OR	Distrib./unattended	115.00		
4	Scholls Ferry, Beaverton, OR	Distrib./unattended	115.00	13.00	
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	Sunset, near Hillsboro, OR	Distrib./unattended	115.00	38.00	
25	Swan Island, Portland, OR	Distrib./unattended	115.00	13.00	
26	Sylvan, near Portland, OR	Distrib./unattended	115.00	13.00	
27	Tabor, Portland, OR	Distrib./unattended	115.00	13.00	
28	Tabor, Portland, OR	Distrib./unattended	57.00		
29	Tektronix, Beaverton, OR	Distrib./unattended	115.00	13.00	
30	Tigard, Tigard, OR	Distrib./unattended	115.00	12.50	
31	Town Center, Portland, OR	Distrib./unattended	115.00	13.00	
32	Tualitin, Tualitin, OR	Distrib./unattended	115.00	13.00	
33	Twilight, Canby, OR	Distrib./unattended	57.00	13.00	
34	University, Salem, OR	Distrib./unattended	115.00	13.00	
35	Urban, Portland, OR	Distrib./unattended	115.00	13.00	
36	Waconda, near Hopmere, OR	Distrib./unattended	57.00	12.50	
37	Wallace, Salem, OR	Distrib./unattended	115.00	13.00	
38	Welches, near Welches, OR	Distrib./unattended	57.00	24.00	13.00
39	Welches, near Welches, OR	Distrib./unattended	57.00	13.00	
40	West Portland, Lower Yard, near Tigard, OR	Distrib./unattended	115.00		

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

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	Monitor, near Monitor, OR	Transm./unattended	230.00	57.00	13.00
2	Murryhill, Beaverton, OR	Transm./unattended	230.00	115.00	13.00
3	North Fork, near Estacada, OR	Transm./unattended	115.00	13.00	
4	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	13.00	
5	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	11.00	
6	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	11.00	
7	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	0.48	
8	Pearl, BPA, near Wilsonville, OR	Transm./unattended	230.00		
9	Pelton, near Madras , OR	Transm./unattended	230.00	13.00	
10	Pelton, near Madras, OR	Transm./unattended	13.00	13.00	
11	Port Westward, near Clatskanie, OR	Transm./unattended	230.00	18.00	16.50
12	River Mill, near Estacada, OR	Transm./unattended	57.00	11.00	
13	Rivergate North Yard, near Portland, OR	Transm./unattended	230.00	115.00	13.00
14	Round Butte, near Madras, OR	Transm./unattended	500.00	230.00	12.50
15	Round Butte, near Madras, OR	Transm./unattended	230.00	12.50	
16	Round Butte, near Madras, OR	Transm./unattended	230.00	66.00	12.50
17	Sand Springs, 22 mi E/22 mi S of Bend, OR	Transm./unattended	500.00		
18	Sherwood, near Six Corners, OR	Transm./unattended	230.00	115.00	13.00
19	Slatt, BPA, Arlington, OR	Transm./unattended	500.00		
20	St. Marys, West Yard, near Beaverton, OR	Transm./unattended	230.00	115.00	13.00
21	Sullivan, West Linn, OR	Transm./Unattended	57.00	4.15	
22	Sycan, 27 mi S of Silver Lake, OR	Transm./unattended	500.00		
23	Trojan, near Rainier, OR	Transm./unattended	230.00	12.50	
24					
25	TOTAL MVa		28978.00	5025.18	400.62
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
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39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	
76	11		Capacitor Banks	3	15,600	1
17	1					2
56	2		Capacitor Banks	4	12,000	3
15	2					4
42	2		Capacitor Banks	2	7,200	5
20	1		Capacitor Banks	2	3,000	6
38	2		Capacitor Banks	2	3,600	7
34	2		Capacitor Banks	4	12,000	8
56	2		Capacitor Banks			9
56	2		Capacitor Banks	5	15,000	10
50	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
41	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
28	1		Capacitor Banks	2	6,000	27
125	1					28
22	2		Capacitor Banks	4	6,000	29
22	1					30
7	1					31
56	2		Capacitor Banks	2	6,000	32
13	1		Capacitor Banks	3	9,000	33
14	1		Capacitor Banks	2	3,000	34
56	2		Capacitor Banks	4	12,600	35
140	2		Capacitor Banks	3	21,600	36
63	3		Capacitor Banks	1	8,400	37
63	3		Capacitor Banks	1	24,000	38
70	1		Capacitor Banks	2	31,200	39
14	1					40

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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.
17	1					1
32	2		Capacitor Banks	4	14,400	2
26	2		Capacitor Banks	2	3,600	3
25	1		Capacitor Banks	1	3,600	4
50	2		Capacitor Banks	2	6,600	5
						6
21	1		Capacitor Banks	2	6,000	7
22	1		Capacitor Banks	2	6,000	8
24	1		Capacitor Banks	2	6,000	9
50	2		Capacitor Banks	3	9,720	10
56	2		Capacitor Banks	4	12,000	11
33	1					12
13	1		Capacitor Banks	2	3,000	13
17	1		Capacitor Banks	2	7,200	14
50	2		Capacitor Banks	4	12,000	15
28	1		Capacitor Banks	2	7,200	16
7	1					17
34	2					18
28	1		Capacitor Banks	2	6,000	19
28	1		Capacitor Banks	2	6,000	20
43	2		Capacitor Banks	4	14,400	21
56	2		Capacitor Banks	4	12,600	22
125	3					23
56	2		Capacitor Banks	4	13,200	24
39	2		Capacitor Banks	2	7,200	25
56	2		Capacitor Banks	2	6,000	26
56	2		Capacitor Banks	3	10,800	27
45	2		Capacitor Banks	4	12,000	28
53	2		Capacitor Banks	4	7,200	29
56	2		Capacitor Banks	4	12,000	30
45	2		Capacitor Banks	2	6,000	31
50	2		Capacitor Banks	4	14,400	32
28	1		Capacitor Banks	2	6,000	33
17	1					34
10	1					35
50	2		Capacitor Banks	3	10,200	36
84	3		Capacitor Banks	6	20,400	37
28	1		Capacitor Banks	2	6,000	38
23	3					39
84	3		Capacitor Banks	6	18,600	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	
53	2		Capacitor Banks	4	12,000	1
34	2		Capacitor Banks	3	10,800	2
17	1		Capacitor Banks	2	6,000	3
15	1					4
19	1					5
29	1					6
34	1					7
42	2		Capacitor Banks	4	9,000	8
20	1		Capacitor Banks	3	15,000	9
45	2		Capacitor Banks			10
39	2		Capacitor Banks	3	9,600	11
56	2		Capacitor Banks	3	10,800	12
45	2		Capacitor Banks	4	12,000	13
31	3		Capacitor Banks	3	15,000	14
20	1		Capacitor Banks	4	18,000	15
28	2					16
56	2		Capacitor Banks	4	14,400	17
						18
280	2					19
81	3		Capacitor Banks	6	18,600	20
15	2					21
34	2		Capacitor Banks	2	7,200	22
50	2		Capacitor Banks	4	12,300	23
28	1		Capacitor Banks	2	6,000	24
55	2		Capacitor Banks	4	12,000	25
28	1					26
50	2		Capacitor Banks	4	13,800	27
28	1		Capacitor Banks	2	6,600	28
17	1		Capacitor Banks	2	6,000	29
22	1					30
84	3		Capacitor Banks	6	18,000	31
						32
22	1		Capacitor Banks	2	7,200	33
22	1		Capacitor Banks	2	6,716	34
28	1		Capacitor Banks	2	6,000	35
78	3		Capacitor Banks	5	10,200	36
						37
28	1		Capacitor Banks	2	6,000	38
						39
15	2		Capacitor Banks	2	3,600	40

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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)	
45	2		Capacitor Banks	4	14,400	1
28	1		Capacitor Banks	2	6,000	2
						3
28	1		Capacitor Banks	2	6,000	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	2	3,600	9
49	2		Capacitor Banks	2	6,000	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
45	2		Capacitor Banks	5	36,000	20
8	1	1				21
6	1					22
328	7		Capacitor Banks	19	94,818	23
100	2					24
50	2		Capacitor Banks	4	12,000	25
22	1		Capacitor Banks	2	6,000	26
22	1		Capacitor Banks	2	6,000	27
						28
56	2		Capacitor Banks	4	12,000	29
45	2		Capacitor Banks	4	12,000	30
56	2		Capacitor Banks	2	6,000	31
56	2		Capacitor Banks	4	13,200	32
28	1		Capacitor Banks	3	19,200	33
22	1		Capacitor Banks	2	7,200	34
112	4		Capacitor Banks	7	43,200	35
41	2		Capacitor Banks	2	6,000	36
20	1					37
6	1		Capacitor Banks	1	12,000	38
18	2		Capacitor Banks	2	6,600	39
			Capacitor Banks	1	24,000	40

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
56	2		Capacitor Banks	4	13,200	1
28	1		Capacitor Banks	3	15,200	2
24	2		Capacitor Banks	3	7,800	3
20	1					4
84	3		Capacitor Banks	6	18,000	5
42	2		Capacitor Banks	4	13,200	6
15	2		Capacitor Banks	1	1,800	7
						8
						9
						10
						11
464	4					12
170	1					13
502	2					14
140	1					15
28	1		Capacitor Banks	2	6,000	16
480	3					17
320	1					18
28	1		Capacitor Banks	2	6,000	19
685	3					20
55	1					21
55	1					22
80	3					23
						24
640	2					25
56	2		Capacitor Banks	4	12,000	26
164	3					27
100	2					28
300	3					29
140	1					30
32	2					31
27	1					32
			Series Capacitor	1	363,000	33
572	2					34
						35
320	1					36
						37
168	1					38
			Reactors	3	180,000	39
640	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
125	1					1
320	1					2
53	3	1				3
8	1					4
64	2					5
2	1					6
1	2					7
						8
164	4					9
3	1					10
450	3					11
32	2					12
520	4		Capacitor Banks	1	24,000	13
561	3		Reactors	12	180,000	14
372	3	2				15
22	1					16
			Series Capacitor	1	546,000	17
640	2					18
						19
960	3		Capacitor Banks	3	108,000	20
33	1					21
			Series Capacitor	1	546,000	22
56	2					23
						24
17713	368	4		403	3,419,104	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 locaton is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulation equipment.

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

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.: 6 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.: 18 Column: a

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

Schedule Page: 426.2 Line No.: 32 Column: a

Switching only.

Schedule Page: 426.2 Line No.: 37 Column: a

Switching only.

Schedule Page: 426.2 Line No.: 39 Column: a

Switching only.

Schedule Page: 426.3 Line No.: 3 Column: a

Switching only. Distribution owned by Columbia River PUD.

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 Columbia River PUD.

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.: 28 Column: a

Switching only.

Schedule Page: 426.3 Line No.: 40 Column: a

Switching only.

Schedule Page: 426.4 Line No.: 11 Column: a

Owned and operated by Bonneville Power Administration. Contribution in aid of constriction made to BPA recorded to FERC account 35300.

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 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.: 22 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.: 23 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

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 35300.

Schedule Page: 426.4 Line No.: 27 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.: 28 Column: a

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 20% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 29 Column: a

Contribution in aid of construction made to Bonneville Power Administration in 2006 in the amount of 261,281 to FERC account 35300.
Contribution in aid of construction made to Bonneville Power Administration in 1995 in the amount of 1,115,709 to FERC account 35300.

Schedule Page: 426.4 Line No.: 33 Column: a

Line compensation only.

Schedule Page: 426.4 Line No.: 35 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.: 37 Column: a

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA in 2012 in the amount of 2,881,411 recorded to FERC account 353.

Schedule Page: 426.4 Line No.: 39 Column: a

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to Boneville Power Administration recorded to FERC account 35300.

Schedule Page: 426.5 Line No.: 8 Column: a

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

Schedule Page: 426.5 Line No.: 9 Column: a

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 66.67% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 10 Column: a

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 66.67% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 15 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.: 16 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.: 17 Column: a

Line compensation only.

Schedule Page: 426.5 Line No.: 19 Column: a

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 35300.

Schedule Page: 426.5 Line No.: 22 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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 Corp	418	4,973,098
4	OPUC Order No. 75-953			
5				
6	Catering Services	Salmon Springs Hospitality Group	921	875,390
7				
8				
9				
10				
11				
12				
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14				
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18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22	Administrative Services	Salmon Springs Hospitality Group	186	814,937
23				
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