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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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** 2015/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 2015/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)* 03/25/2016
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".

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 2015/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)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Two copies will be submitted [ ] No annual report to stockholders is prepared		

GENERAL INFORMATION

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

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

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

Oregon - Incorporated July 25, 1930

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

Property of respondent was not so held during the year.

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

The respondent is engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The respondent also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its retail customers.

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 2015/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.

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 2015/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	121 SW Salmon Street Corporation	Company has leased the	100	
2		headquarters complex in		
3		Portland, Oregon and sub-		
4		leases the complex to		
5		Respondent.		
6				
7	World Trade Center Northwest Corporation	Company is the holder of the	100	
8	(A wholly-owned subsidiary of 121 SW Salmon	World Trade Center Franchise		
9	Street Corporation)			
10				
11	Salmon Springs Hospitality Group	Company provides food	100	
12		catering services.		
13				
14	SunWay 2, LLC	Solar power generation	Dissolved	
15				
16	SunWay 3, LLC	Solar power generation	0.01	
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

Schedule Page: 103 Line No.: 14 Column: c

On January 5, 2015, PGE acquired the assets and liabilities of SunWay 2, LLC, a variable interest entity, at net book value. The entity was subsequently dissolved.

Schedule Page: 103 Line No.: 16 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 2015/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	767,190
2	Senior Vice President of Finance, Chief Financial	James F. Lobdell	388,883
3	Officer and Treasurer		
4	Senior Vice President, Power Supply & Operations,	Maria M. Pope	437,391
5	and Resource Strategy		
6	Senior Vice President, Customer Service	William O. Nicholson	306,462
7	Transmission and Distribution		
8	Vice President, General Counsel and Corporate	J. Jeffery Dudley	358,400
9	Compliance Officer		
10	Vice President, Public Policy	W. David Robertson	283,704
11	Vice President, Customer Strategies and Business	Carol A. Dillin	281,713
12	Development		
13	Vice President, Human Resources,	Arleen N. Barnett	279,782
14	Diversity and Inclusion, and Administration		
15	Vice President, Transmission and Distribution	Larry N. Bekkedahl	274,640
16	Vice President, Information Technology and Chief	Campbell A. Henderson	246,644
17	Information Officer		
18	Vice President, Nuclear and Power Supply/Generation	Stephen M. Quennoz	229,526
19	Vice President, Customer Service Operations	Kristin A. Stathis	228,544
20	Vice President, Power Supply Generation	Bradley Y. Jenkins	205,872
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			

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

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

Schedule Page: 104 Line No.: 13 Column: a

Retired from position effective December 31, 2015.

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

Retired from position effective September 30, 2015.

Schedule Page: 104 Line No.: 20 Column: a

Appointed to position effective September 1, 2015.

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 2015/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	Scottsdale, Arizona
6	Chair of the Board of Portland General Electric Company	
7	Retired Chief Executive Officer of	
8	Arizona Public Service Company	
9	David A. Dietzler	Lake Oswego, Oregon
10	Retired Partner of KPMG LLP	
11	Kirby A. Dyess	Beaverton, Oregon
12	Principal, Austin Capital Management LLC	
13	Mark B. Ganz	Portland, Oregon
14	President and Chief Executive Officer of	
15	Cambia Health Solutions	
16	Kathryn J. Jackson	Sewickley, Pennsylvania
17	Director, Energy & Technology Consulting with KeySource	
18	Neil J. Nelson	Portland, Oregon
19	President and Chief Executive Officer of Siltronic Corp.	
20	M. Lee Pelton	Boston, Massachusetts
21	President of Emerson College	
22	James J. Piro	Portland, Oregon
23	President and Chief Executive Officer of	
24	Portland General Electric Company	
25	Charles W. Shivery	Avon, Connecticut
26	Retired Chairman of Northeast Utilities	
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
48		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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		
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		

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 2015/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
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					

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 2015/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
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				

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. In December 2014, PGE acquired an additional 10% undivided interest from another co-owner in the Boardman Plant, and associated equipment and facilities, as well as certain contracts and other rights related to that co-owner's ownership interest in the Boardman Plant. The original cost of the 10% of the Boardman Plant and generator tie lines acquired at December 31, 2014 was estimated at $67 million.

On September 19, 2014, PGE filed an application that requested authorization for the acquisition of the rights, titles, and interests associated with this transaction pursuant to section 203(a)(1) of the Federal Power Act (FPA), and included proposed accounting entries. On November 14, 2014, the Federal Energy Regulatory Commission (FERC) concluded that the proposed transaction was consistent with public interest and authorized the transaction (Docket EC14-147-000).

In December 2014, the Company executed the accounting entries. For further detail on the final accounting entries, see p. 219 of this Form 1. On April 20, 2015, PGE submitted to the FERC the required journal entries and narrative explanations for PGE to acquire all the rights, titles, and interests of the co-owner, in accordance with Electric Plant Instruction No. 5 of the Uniform System of Accounts and Electric plant purchased or sold (Account 102).

Based on subsequent discussions with the FERC Staff, PGE updated (Docket AC15-110-000) one of the proposed journal entries to clear the negative acquisition adjustment immediately instead of amortizing the balance over the remaining life of the plant. On July 6, 2015, the FERC concluded that the proposed journal entries were approved for accounting purposes (Docket AC15-110-000).

4. None

5. None

6. Pursuant to PGE's application, the FERC, on February 5, 2016, issued an order in Docket No. ES15-73-000 that authorizes the Company to issue up to $900 million of short-term debt through February 6, 2018. 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.

During the first quarter of 2015, PGE determined that a $500 million aggregate revolving credit facility capacity would be sufficient to meet its liquidity needs and accordingly, in March 2015, reduced its aggregate revolving credit capacity from $700 million to $500 million. As of December 31, 2015, PGE has a $500 million revolving credit facility, which is scheduled to expire in November 2019.

Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, as backup for commercial paper borrowings, and to 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 credit facility.

PGE classifies any borrowings under the revolving credit facility and outstanding commercial paper as Notes Payable on the Comparative Balance Sheet.

Under the revolving credit facility, as of December 31, 2015, PGE had no borrowings outstanding and no of letters of credit issued.

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 revolving credit facility. As of December 31, 2015, PGE had $6 million in commercial paper outstanding, which was backed by the revolving credit facility, leaving an aggregate available capacity under the revolving credit facility of $494 million.

In addition, PGE has four letter of credit facilities providing $160 million capacity under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these four facilities, $108 million of letters of credit were outstanding, as of December 31, 2015.

During 2015, as authorized under the Public Utility Commission of Oregon (OPUC) Order 14-399, PGE issued a total of $145 million of First Mortgage Bonds (FMBs) as follows:2015, as authorized under the Public Utility Commission of Oregon (OPUC) Order 14-399, PGE issued a total of $145 million of First Mortgage Bonds (FMBs) as follows:

- In January, issued $75 million of 3.55% Series FMBs due 2030; and
- In May, issued $70 million of 3.5% Series FMBs due 2035.

In January 2016, under the same OPUC Order, the Company issued $140 million of 2.51% Series FMBs due 2021.

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, 2015, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the Comparative Balance Sheet with respect to these indemnities.

7. None

8. None

9. Legal Proceedings:

Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court; and Morgan v. Portland General Electric Company, Marion County Circuit Court.

In January 2003, two class action suits were filed in Marion County Circuit Court (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 the Company's former Trojan nuclear power plant (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 Supreme 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 Circuit Court. In October 2006, the Circuit Court issued an Order of Abatement in response to the ruling of the Oregon Supreme Court, abating the class actions for one year.

Following the October 2014 decision of the Oregon Supreme Court upholding the OPUC refund order in the related Trojan regulatory proceeding, the Circuit Court granted PGE’s motion to lift the abatement in June 2015. PGE has filed a motion for summary judgment dismissing the lawsuits. Oral argument took place on July 27, 2015 and the Circuit Court has not yet issued its decision. Following oral argument on PGE’s motion for summary judgment, Plaintiffs moved to amend the complaints. PGE opposed the request to amend and the Court has not yet issued its decision.

Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western System Power Pool Agreement, Federal Energy Regulatory Commission and Ninth Circuit Court of Appeals (collectively, 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. Although FERC's original decision terminated the proceeding and denied the claims for refunds, upon appeal of this decision to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit), the Ninth Circuit remanded the case to the FERC to, among other things, address market manipulation evidence and account for the evidence in any future orders regarding the award or denial of refunds in the proceedings.

In response to the Ninth Circuit remand, the FERC issued several procedural orders that established an evidentiary hearing, defined the scope of the hearing, and described the burden of proof that must be met to justify abrogation of the contracts at issue and the imposition of refunds. The orders 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 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. The FERC also expanded the scope of the hearing to allow parties to pursue refunds for transactions between January 1, 2000 and December 24, 2000 under Section 309 of the Federal Power Act by showing violations of a filed tariff or rate schedule or of a statutory requirement. 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. Refund claimants appealed these procedural orders at the Ninth Circuit. On December 17, 2015, the Ninth Circuit held that the FERC reasonably applied the *Mobile-Sierra* presumption to the class of contracts at issue in the proceedings and dismissed evidentiary challenges related to the scope of the proceeding.

In response to the evidence and arguments presented during the remand hearing, in May 2015, the FERC issued an order finding that the refund proponents had failed to meet the *Mobile-Sierra* burden with respect to all but one respondent. In December 2015, the FERC denied all requests for rehearing of its order. With respect to the remaining respondent, FERC ordered additional proceedings, and a January 2016 revised initial decision has now recommended that certain contracts by such respondent be subject to refund.

The Company has settled all of the direct claims asserted against it in the proceedings for an immaterial amount. The settlements and associated FERC orders have not fully eliminated the potential for so-called "ripple claims," which have been described by the FERC as "sequential claims against a succession of sellers in a chain of purchases that are triggered if the last wholesale purchaser in the chain is entitled to a refund." However, the remaining respondent subject to the revised initial decision has stated on the record that it will not pursue ripple claims. Therefore, unless the current FERC orders are overturned or modified on appeal, the Company does not believe that it will incur any material loss in connection with this matter.

Sierra Club and Montana Environmental Information Center v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and PacifiCorp, U.S. District Court for the District of Montana.

In July 2012, PGE received a Notice of Intent to Sue (Notice) for violations of the CAA at Colstrip Steam Electric Station (CSES) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other CSES co-owners, including Talen Montana, LLC - the operator of CSES. PGE has a 20% ownership interest in Units 3 and 4 of CSES. The Notice alleges certain violations of the CAA, and stated that the Sierra Club and MEIC would: 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.

The Sierra Club and MEIC asserted that the CSES owners violated the Title V air quality operating permit during portions of 2008 and 2009 and 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. The Sierra Club and MEIC also asserted violations of opacity provisions of the CAA.

In March 2013, the Sierra Club and MEIC sued the CSES co-owners, including PGE, for these and additional alleged violations of various environmental related regulations. The plaintiffs are seeking relief that includes civil penalties and an injunction preventing the co-owners from operating CSES except in accordance with the CAA, the Montana State Implementation Plan, and the plant's federally enforceable air quality permits. In addition, plaintiffs are seeking civil penalties against the co-owners including $32,500 per day for each violation occurring through January 12, 2009, and $37,500 per day for each violation occurring thereafter.

In May 2013, the defendants filed a motion to dismiss 36 of the 39 claims in the complaint. In September 2013, the plaintiffs filed a motion for partial summary judgment regarding the appropriate method of calculating emissions increases. Also in September 2013, the plaintiffs filed an amended complaint that withdrew Title V and opacity claims, added claims associated with two 2011 projects, and expanded the scope of certain claims to encompass approximately 40 additional projects.

In July 2014, the court denied defendants' motion to dismiss and the plaintiffs' motion for partial summary judgment. In August 2014, the plaintiffs filed a second amended complaint. The defendants' response to the second amended complaint was filed in September 2014. The second amended complaint continues to seek injunctive relief, declaratory relief, and civil penalties for alleged violations of the federal Clean Air Act. The plaintiffs state in the second amended complaint that it was filed, in part, to comply with the court's ruling on the defendants' motion to dismiss and plaintiffs' motion for partial summary judgment. Discovery in this matter is complete. The parties filed various summary judgment motions during the summer of 2015. Oral argument on those motions occurred on December 1, 2015. On or about December 31, 2015, the Magistrate Judge issued Findings and Recommendations that, if adopted by the trial court, would result in dismissal of several of the plaintiffs' claims. The case is currently set for trial on May 6, 2016.

10. None

11. (Reserved)

12. None

13. Changes in Officers:

    On March 26, 2015, Stephen M. Quennoz, Vice President, Nuclear and Power Supply/Generation, notified the Company of his decision to retire effective September 30, 2015.

    In August 2015, Arleen N. Barnett, Vice President, Human Resources, Diversity and Inclusion, and Administration notified the Company of her decision to retire effective December 31, 2015.

    On September 1, 2015, Bradley Y. Jenkins, duly appointed, assumed the position of Vice President of Generation.

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 2015/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	8,722,574,599	8,301,464,412
3	Construction Work in Progress (107)	200-201	545,045,342	417,028,226
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		9,267,619,941	8,718,492,638
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,094,637,726	3,847,673,122
6	Net Utility Plant (Enter Total of line 4 less 5)		5,172,982,215	4,870,819,516
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)		5,172,982,215	4,870,819,516
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		40,534,473	32,701,374
19	(Less) Accum. Prov. for Depr. and Amort. (122)		14,460,460	13,489,880
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	2,579,954	3,885,975
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)		77,053,592	126,574,714
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		62,569	593,801
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		105,770,128	150,265,984
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		3,504,212	6,429,345
36	Special Deposits (132-134)		33,201,844	11,090,727
37	Working Fund (135)		22,200	23,061
38	Temporary Cash Investments (136)		0	120,000,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		129,569,243	130,571,577
41	Other Accounts Receivable (143)		34,045,749	24,041,075
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		6,141,525	6,408,988
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		10,741	462,288
45	Fuel Stock (151)	227	37,743,684	39,025,434
46	Fuel Stock Expenses Undistributed (152)	227	0	3,333,157
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	39,858,519	35,969,661
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	1,162,155	820,002

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	4,074,812	3,164,304
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)		45,186,373	41,695,558
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)		94,792,424	93,387,801
62	Miscellaneous Current and Accrued Assets (174)		88,407	23,409,706
63	Derivative Instrument Assets (175)		10,380,301	7,326,888
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		62,569	593,801
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)		427,436,570	533,747,795
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		11,429,778	11,761,685
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	65,583	0
72	Other Regulatory Assets (182.3)	232	639,518,308	614,275,595
73	Prelim. Survey and Investigation Charges (Electric) (183)		444,923	211,533
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)		156,964	229,131
77	Temporary Facilities (185)		13,785	0
78	Miscellaneous Deferred Debits (186)	233	12,588,452	11,776,807
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)		16,341,107	15,194,431
82	Accumulated Deferred Income Taxes (190)	234	369,627,897	324,142,876
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,050,186,797	977,592,058
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,756,375,710	6,532,425,353

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 2015/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	1,199,786,255	911,154,338
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	18,838,745	17,842,676
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	23,073,915	10,832,643
11	Retained Earnings (215, 215.1, 216)	118-119	1,070,047,158	1,000,106,458
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	153,969	183,976
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)	-7,923,203	-7,704,212
16	Total Proprietary Capital (lines 2 through 15)		2,257,829,009	1,910,750,593
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,204,400,000	2,196,400,000
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	83,849	305,089,838
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		655,815	713,235
24	Total Long-Term Debt (lines 18 through 23)		2,203,828,034	2,500,776,603
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)		10,370,510	9,329,914
29	Accumulated Provision for Pensions and Benefits (228.3)		371,521,184	349,067,148
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		10,309,396	9,531,276
32	Long-Term Portion of Derivative Instrument Liabilities		160,800,699	122,092,454
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		150,704,725	115,704,479
35	Total Other Noncurrent Liabilities (lines 26 through 34)		703,706,514	605,725,271
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		5,999,500	0
38	Accounts Payable (232)		202,835,442	239,924,949
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		368,204	509,839
41	Customer Deposits (235)		15,183,863	14,702,206
42	Taxes Accrued (236)	262-263	12,645,325	10,295,412
43	Interest Accrued (237)		24,643,802	26,383,635
44	Dividends Declared (238)		27,679,814	22,888,174
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 2015/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)		12,455,197	11,728,645
48	Miscellaneous Current and Accrued Liabilities (242)		39,159,727	33,877,206
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		290,388,592	228,023,469
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		160,800,699	122,092,454
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)		470,558,767	466,241,081
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	11,447,372	5,174,407
60	Other Regulatory Liabilities (254)	278	106,949,335	127,549,631
61	Unamortized Gain on Reaquired Debt (257)		58,377	66,429
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		722,917,080	650,919,959
64	Accum. Deferred Income Taxes-Other (283)		279,081,222	265,221,379
65	Total Deferred Credits (lines 56 through 64)		1,120,453,386	1,048,931,805
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,756,375,710	6,532,425,353

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 2015/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	1,914,921,070	1,926,578,668		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,043,679,349	1,091,797,485		
5	Maintenance Expenses (402)	320-323	138,565,097	130,451,217		
6	Depreciation Expense (403)	336-337	252,397,595	241,730,943		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	5,026,773	3,569,396		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	38,364,891	25,400,209		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		-13,299,647	3,500,000		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		33,462,767	25,217,405		
13	(Less) Regulatory Credits (407.4)		15,271,409	1,982,810		
14	Taxes Other Than Income Taxes (408.1)	262-263	114,643,947	106,846,515		
15	Income Taxes - Federal (409.1)	262-263	4,811,998	20,555,463		
16	- Other (409.1)	262-263	809,455	2,118,584		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	257,577,936	257,916,974		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	216,856,401	217,223,960		
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)		35,337			
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		2,952,034	2,087,165		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,646,899,722	1,691,984,586		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		268,021,348	234,594,082		

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 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,914,921,070	1,926,578,668					2
						3
1,043,679,349	1,091,797,485					4
138,565,097	130,451,217					5
252,397,595	241,730,943					6
5,026,773	3,569,396					7
38,364,891	25,400,209					8
						9
-13,299,647	3,500,000					10
						11
33,462,767	25,217,405					12
15,271,409	1,982,810					13
114,643,947	106,846,515					14
4,811,998	20,555,463					15
809,455	2,118,584					16
257,577,936	257,916,974					17
216,856,401	217,223,960					18
						19
						20
35,337						21
						22
						23
2,952,034	2,087,165					24
1,646,899,722	1,691,984,586					25
268,021,348	234,594,082					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		268,021,348	234,594,082		
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)					
33	Revenues From Nonutility Operations (417)		3,464,148	6,912,989		
34	(Less) Expenses of Nonutility Operations (417.1)		3,640,827	5,996,233		
35	Nonoperating Rental Income (418)		2,591,798	2,775,814		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	239,353	283,851		
37	Interest and Dividend Income (419)		571,809	461,993		
38	Allowance for Other Funds Used During Construction (419.1)		21,253,692	36,579,261		
39	Miscellaneous Nonoperating Income (421)		-749,842	-203,932		
40	Gain on Disposition of Property (421.1)			293,563		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		23,730,131	41,107,306		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,688,692	1,807,066		
46	Life Insurance (426.2)		77,598	-137,891		
47	Penalties (426.3)		360,566	462,650		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		866,200	851,625		
49	Other Deductions (426.5)		3,286,482	2,220,161		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		6,279,538	5,203,611		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,315,094	1,317,874		
53	Income Taxes-Federal (409.2)	262-263	-1,035,472	-527,274		
54	Income Taxes-Other (409.2)	262-263	-248,431	-125,648		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	179,279	1,731,121		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	748,148	3,368,697		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-537,678	-972,624		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		17,988,271	36,876,319		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		118,606,342	111,306,270		
63	Amort. of Debt Disc. and Expense (428)		1,022,130	1,007,332		
64	Amortization of Loss on Reaquired Debt (428.1)		1,518,585	1,585,063		
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)		5,242,336	4,618,754		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		12,519,680	22,440,859		
70	Net Interest Charges (Total of lines 62 thru 69)		113,861,661	96,068,508		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		172,147,958	175,401,893		
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)		172,147,958	175,401,893		

Schedule Page: 114 Line No.: 10 Column: c

Includes $16 million credit amortization of the Trojan spent fuel refund received from the US Dept of Energy as approved in OPUC Order No. 14-422, as amounts are refunded to customers during 2015.

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 2015/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		996,253,663	908,538,384
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)		171,908,605	175,118,042
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			-102,237,265	(87,605,185)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-102,237,265	(87,605,185)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		269,360	202,422
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,066,194,363	996,253,663
	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)		1,070,047,158	1,000,106,458
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		183,976	102,547
50	Equity in Earnings for Year (Credit) (Account 418.1)		239,353	283,851
51	(Less) Dividends Received (Debit)		270,000	275,000
52	Transfer In Due to Dissolution of Subsidiary		640	72,578
53	Balance-End of Year (Total lines 49 thru 52)		153,969	183,976

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 2015/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)	172,147,958	175,401,893
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	295,789,259	270,700,548
5	Amortization of Debt Discount	2,548,767	2,584,343
6	Amortization of Unrecovered Plant	-13,299,647	3,500,000
7	Price Risk Management	59,311,710	44,418,752
8	Deferred Income Taxes (Net)	40,152,666	39,055,438
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	-10,222,879	7,847,174
11	Net (Increase) Decrease in Inventory	-526,612	-13,173,045
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	5,986,805	-12,540,667
14	Net (Increase) Decrease in Other Regulatory Assets	-1,848,803	-12,340,869
15	Net Increase (Decrease) in Other Regulatory Liabilities	-11,003,687	31,874,688
16	(Less) Allowance for Other Funds Used During Construction	21,253,692	36,579,261
17	(Less) Undistributed Earnings from Subsidiary Companies	239,353	283,851
18	Other: Margin Deposit	-21,629,460	-2,066,385
19	Other Operating	19,122,858	19,942,810
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	515,035,890	518,341,568
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-591,283,708	-1,004,912,636
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-7,833,099	-3,135,770
30	(Less) Allowance for Other Funds Used During Construction	-21,253,692	-36,579,261
31	Other (provide details in footnote):		
32	Other Capital Activities	-17,495,919	-22,248,332
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-595,359,034	-993,717,477
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Sale of Utility Property		5,453,825
39	Investments in and Advances to Assoc. and Subsidiary Companies	1,306,021	174,844
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Sales Tax Refund	23,321,299	
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

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	-2,574,918	1,607,669
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 Decomm Securities	-19,141,609	-18,895,792
54	Sales of Trojan Decomm Securities	21,726,468	16,756,552
55	Distribution from (Contribution to) Nuclear Decommissioning Trust	50,000,000	-5,852,567
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-520,721,773	-994,472,946
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	145,000,000	585,000,000
62	Preferred Stock		
63	Common Stock	271,470,729	
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	5,999,500	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	422,470,229	585,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-442,005,989	-5,990
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Debt Issue Costs	-629,975	-1,816,907
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-97,074,376	-86,743,023
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-117,240,111	496,434,080
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-122,925,994	20,302,702
87			
88	Cash and Cash Equivalents at Beginning of Period	126,452,406	106,149,704
89			
90	Cash and Cash Equivalents at End of period	3,526,412	126,452,406

Schedule Page: 120 Line No.: 6 Column: b

Includes $16.7 million of amortization of Trojan spent fuel settlement as amounts are refunded to customers.

Schedule Page: 120 Line No.: 26 Column: c

Includes $23 million accrued sales tax refund related to Tucannon River Wind Farm.

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

The amount of $5 million represents proceeds of $4.1 million from Sale of the Hawthorne building, $0.5 million for sale of Dana Substation and $0.4 million for sale of Lone Fir property.

Schedule Page: 120 Line No.: 43 Column: b

Sales Tax Refund received related to Tucannon River Wind Farm.

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

Distribution from Nuclear Decommissioning Trust being returned to customers over the three year period that began January 1, 2015.

Schedule Page: 120 Line No.: 63 Column: b

Net amount received in exchange for shares issued under Equity Forward Sale Agreement.

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.

PAGE 122 INTENTIONALLY LEFT BLANK
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 Year
Cash (131)	$ 6,429,345	$ 3,504,212
Working Funds (135)	23,061	22,200
Temporary Cash Investments (136)	120,000,000	—
	$ 126,452,406	$ 3,526,412

	2014	2015
Cash paid during the year:		
Interest	$ 108,145,039	$ 120,372,682
Allowance for borrowed funds used during construction	(22,440,859)	(12,519,680)
	$ 85,704,180	$ 107,853,002
Income Taxes	$ 22,050,850	$ 2,655,700
Non-cash investing and financing activities:		
Accrued capital additions	$ 70,433,493	$ 31,912,785
Accrued dividends payable	22,888,174	27,679,814
Accrued sales tax refund related to Tucannon River Wind Farm	23,355,665	—
Preliminary engineering transferred to Construction work in progress	404,336	89,854

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, 2015, PGE served 852,164 retail customers with a service area population of approximately 1.8 million, comprising approximately 46% of the state’s population.

As of December 31, 2015, PGE had 2,646 employees, with 764 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 713 and 51 employees and expire at the end of February 2016, (the Company is currently in negotiation to renew or extend) and August 2017, 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 Comparative Balance Sheet be classified differently than that required by GAAP, primarily the classification of components of accumulated deferred income taxes, long-term debt, regulatory assets and liabilities, and 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 Income 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.

Reclassification

To conform to the 2015 presentation, PGE has reclassified $6 million of Other: Proceeds Received from Trojan Spent Fuel Legal Settlement to Other Operating in the Statement of Cash Flows as of December 31, 2014.

Subsequent events

PGE has evaluated the impact of events occurring after December 31, 2015 up to February 12, 2016, the date that the Company's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through March 25, 2016. These financial statements include all necessary adjustments and disclosures resulting from such evaluations.

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 Temporary Cash Investments, of which PGE had none as of December 31, 2015 and $120 million as of December 31, 2014.

Accounts Receivable

Customer Accounts Receivable are recorded at invoiced amounts based on prices that are subject to federal (FERC) and state (OPUC) regulations. Balances do not bear interest; however, late fees are assessed beginning 16 business days after the invoice due date. Accounts that are inactivated due to nonpayment are charged-off in the period in which the receivable is deemed uncollectible, but no sooner than 45 business days after the due date of the final invoice.

Provisions for uncollectible accounts related to retail sales are charged to Administrative and General Expenses and are recorded in the same period as the related Operating Revenues, with an offsetting credit to Accumulated Provision for Uncollectible Accounts. Such estimates are based on management's assessment of the probability of collection, aging of Customer Accounts Receivable, bad debt write-offs, actual customer billings, and other factors.

Provisions for uncollectible accounts related to wholesale sales are charged to Purchased Power and are recorded periodically based on a review of counterparty non-performance risk and contractual right of offset when applicable. There have been no material write-offs of accounts receivable related to wholesale sales in 2015 or 2014 .

Price Risk Management

PGE engages in price risk management activities, utilizing financial instruments such as forward, future, swap, and option contracts for electricity, natural gas, oil, and foreign currency. These instruments are measured at fair value and recorded on the Comparative Balance Sheet as assets or liabilities from price risk management activities. 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 may meet the requirements for treatment under the normal purchases and normal sales scope exception. Such contracts are not recorded at fair value and are recognized under accrual accounting.

Price risk management 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.

Electricity and natural gas sale and purchase transactions that are physically settled are recorded in Operating Revenues and Purchased Power, respectively, upon settlement.

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 reflected as Special Deposits in the Comparative Balance Sheet and were $33 million and $11 million as of December 31, 2015 and 2014, respectively. Letters of credit provided as collateral are not recorded on the Company's Comparative Balance Sheet and were $63 million and $30 million as of December 31, 2015 and 2014, 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, as well as fuel for use in its generating plants. Fuel inventories include natural gas, coal, and oil. Periodically, the Company assesses the realizability of inventory for purposes of determining that inventory is recorded at the lower of average cost or market.

Utility Plant

Capitalization Policy

Utility Plant is capitalized at its original cost, which includes 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 (CWIP) in Utility Plant on the Comparative Balance Sheet. 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. Costs disallowed for recovery in customer prices, if any, are charged to expense at the time such disallowance becomes probable.

PGE records AFDC, which is intended to represent the Company's cost of funds used for construction purposes, 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 Statement of Income. The average rate used by PGE was 7.3% in 2015 and 7.4% in 2014. AFDC from borrowed funds was $13 million in 2015 and $22 million in 2014 and is reflected as a reduction to Interest Charges. AFDC from equity funds was $21 million in 2015 and $37 million in 2014 and is included in Other Income.

The Company is constructing the Carty Generating Station (Carty), a 440 MW baseload natural gas-fired generating plant in Eastern Oregon, located adjacent to the Boardman coal plant. As of December 31, 2015, PGE had $424 million, including $41 million of AFDC, included in CWIP for the project. On November 3, 2015, the OPUC issued an order approving settlements reached in PGE's 2016 GRC filing, including capital costs of up to $514 million, including AFDC, for Carty and that Carty will be included in customer prices when the plant is placed in service, provided that occurs by July 31, 2016.

In 2013, the Company entered into an agreement (Construction Agreement) for engineering, procurement and construction of Carty with Abeinsa Abener Teyma General Partnership (Contractor or Abeinsa). On December 18, 2015, the Company declared Abeinsa in default under multiple provisions of the Construction Agreement and terminated the Construction Agreement. Liberty Mutual Surety and Zurich North America (Sureties) have provided a performance bond of $145.6 million under the Construction Agreement. The Company had required Abeinsa to enter into the performance bond to guarantee satisfactory completion of the project in the event the Contractor failed to fulfill its obligations under the Construction Agreement. Following termination of the Construction Agreement, PGE, in consultation with the Sureties, brought on new contractors and construction resumed during the week of December 21, 2015. The Company has been in discussions with the Sureties regarding their obligations under the performance bond. The Company believes that the Sureties will have an obligation under the performance bond to contribute funds towards the completion of Carty.

On January 28, 2016, PGE received notice from the International Court of Arbitration that Abengoa S.A., the parent company of the Contractor, had submitted a Request for Arbitration in which it alleged that the Company's termination of the Construction Agreement was wrongful and in breach of the agreement terms and does not give rise to liability of Abengoa S.A. under the terms of a guaranty in favor of PGE pursuant to which Abengoa S.A. agreed to guaranty certain obligations of the Contractor under the Construction Agreement. PGE disagrees with the assertions in the Request for Arbitration and on February 29, 2016 filed a Complaint and Motion for Preliminary Injuction in the U.S. District Court for the District of Oregon seeking to have the arbitration claim dismissed on the grounds that the Company has not made a demand under the Abengoa S.A. guaranty, and therefore the matter is not ripe for arbitration.

On March 9, 2016, the Sureties delivered a letter to the Company denying liability in whole under the performance bond. In the letter, the Sureties made the following assertions in support of their determination:

- that, because the Contractor and its parent company, Abengoa S.A., have alleged that PGE wrongfully terminated the Construction agreement and have requested arbitration of the claim, PGE must disprove such claim as a condition precedent to recovery under the Performance Bond; and

- that, irrespective of the outcome of the foregoing wrongful termination claim, the Sureties have various contractual and equitable defenses to payment and are not liable to PGE for any amount under the Performance Bond.

The Company disagrees with the foregoing assertions and on March 23, 2016 filed a breach of contract action against the Sureties in the U.S. District Court for the District of Oregon. The Company's complaint disputes the Sureties' assertion that the Company wrongfully terminated the Construction Agreement and asserts that the Sureties are responsible for the payment of all damages sustained by PGE as a result of the Sureties' breach of contract, including damages in excess of the $145.6 million stated amount of the Performance Bond. Such damages include additional costs incurred by PGE to complete Carty through the warranty period for the project.

As a result of the termination of the Construction Agreement, the transition to a new construction team, and related matters, additional costs are expected to be incurred to complete construction of Carty, including, among other things, costs related to determining the remaining scope of construction, re-performing work performed by the Contractor that did not meet specifications, completing an inventory of materials either on-site, ordered or in transit, preparing work plans for contractors, identifying new contractors, negotiating contracts, procuring additional materials, completing unfinished construction, and removing liens on the property. PGE currently expects the total cost of Carty could range from $635 million to $670 million, including AFDC, and is targeted to be placed in service in July 2016. However, due to uncertainties relating to the transition to the new construction team and any other unknown factors related to the completion of construction, estimated completion date and costs could change. The total project cost would be reduced by any amounts received pursuant to the Sureties’ obligations under the performance bond. However, the amount of any such proceeds remains uncertain and cannot be reasonably estimated at this time.

In the event the total project costs incurred by PGE, net of any amounts received under the performance bond, exceed the OPUC’s approved amount of $514 million, including AFDC, the Company would seek approval to recover the excess amounts in customer prices in a subsequent general rate case (GRC) proceeding. However, there is no assurance that such recovery would be granted by the OPUC. If the Carty placed in service date were to be delayed beyond July 31, 2016, PGE would pursue one or more alternative avenues to obtain OPUC approval for the inclusion of Carty costs in customer prices in future GRC filings. Under such circumstance, the Company might not be able to recover some, or all, of the net revenue requirements for Carty from the date Carty is placed into service until the time approved rates go in effect.

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 3.6% in 2015 and 2014. Estimated asset retirement removal costs included in Depreciation Expense were $32 million in 2015 and $57 million in 2014.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of asset retirement obligations (AROs) and asset retirement removal costs. The studies are conducted at a minimum of every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. The most recent depreciation study was completed for 2013, with an order received from the OPUC in September 2014 authorizing new depreciation rates effective January 1, 2015.

Thermal generation 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 2059. 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):

Generation, excluding thermal:	
Hydro	95
Wind	30
Transmission	57
Distribution	45
General	12

When property is retired and removed from service, the original cost of the depreciable property units, net of any related salvage value, is charged to accumulated depreciation. Cost of removal expenditures are recorded against AROs or to accumulated depreciation.

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Accumulated amortization was $227 million and $191 million as of December 31, 2015 and 2014, respectively, with amortization expense of $38 million in 2015 and $25 million in 2014. Future estimated amortization expense as of December 31, 2015 is as follows: $43 million in 2016; $40 million in 2017; $39 million in 2018; $33 million in 2019; and $23 million in 2020.

Marketable Securities

All of PGE's investments in marketable securities in the Non-qualified benefit plan trust and Nuclear decommissioning trust, included in Other Special Funds on the Comparative Balance Sheet, are classified as trading. These securities are classified as noncurrent because they are not available for use in operations. 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 Other Regulatory Liabilities or Assets, respectively, for future ratemaking treatment. The cost of securities sold is based on the average cost method.

Regulatory Accounting

Regulatory Assets and Liabilities

As a rate-regulated enterprise, PGE applies regulatory accounting, which results in the creation of regulatory assets and 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. NVPC consists of i) the cost of power purchased and fuel used to generate electricity to meet PGE's retail load requirements, as well as the cost of settled electric and natural gas financial contracts, all of which is classified as Purchased Power in the Company's Statement of Income; and is net of ii) wholesale sales, which are classified as Operating Revenues in the Statement of Income.

To the extent actual NVPC, subject to certain adjustments, is outside the deadband range, the PCAM provides for 90% of the excess variance to be collected from or refunded to customers. Pursuant to a regulated earnings test, a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for that year being no less than 1% above the Company's latest authorized ROE, while a collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. PGE's authorized ROE was 9.68% for 2015 and 9.75% for 2014.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues in the Company's Statement of Income, while any estimated collection from customers is recorded as a reduction in Purchased Power. A final determination of any customer refund or collection is made in the following year by the OPUC through a public filing and review. The PCAM has resulted in no collection from, or refund to, customers since 2011.

Asset Retirement Obligations

Legal obligations related to the future retirement of tangible long-lived assets are classified as AROs on PGE's Comparative Balance Sheet. An ARO is recognized in the period in which the legal obligation is incurred, and when the fair value of the liability can be reasonably estimated. 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 dismantlement and restoration costs is capitalized and included in Utility Plant, net on the Comparative Balance Sheet with a corresponding offset to ARO. Such estimates are 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 Expense for Asset Retirement Costs in the Statement of Income. Changes in the ARO resulting from the passage of time (accretion) is based on the original discount rate and recognized as an increase in the carrying amount of the liability and as a charge to accretion expense, which is classified as Depreciation Expense for Asset Retirement Costs in the Company's Statement of Income.

For additional information concerning the Company's AROs, see Note 7, Asset Retirement Obligations.

The difference between the timing of the recognition of the AROs' depreciation and accretion expenses and the amount included in customers' prices is recorded as a regulatory asset or liability in the Company's Comparative Balance Sheet. PGE had a regulatory liability related to AROs in the amount of $45 million as of December 31, 2015 and $39 million as of December 31, 2014. For additional information concerning the Company's regulatory liability related to AROs, see Note 6, Regulatory Assets and Liabilities.

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 Comparative Balance Sheet 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 Statement of Income. Amounts collected from customers are included in Operating Revenue and amounts due to taxing authorities are included in Taxes Other Than Income Taxes and totaled $43 million in 2015 and $42 million in 2014.

Retail revenue is billed monthly based on meter readings taken throughout the month. Accrued Utility Revenues represents the revenue earned from the time of the last meter read date through the last day of the month, a period which has not been billed as of the last day of the month. Accrued Utility Revenues are 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 recognizes 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 vesting 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 $89 million as of December 31, 2015 and 2014 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 Comparative Balance Sheet.

PGE records any interest and penalties related to income tax deficiencies in Net Interest Charges and Penalties, respectively, in the Statement of Income.

Recent Accounting Pronouncements

Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASU 2014-09), creates a new Topic 606 and supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition*, and most industry-specific guidance throughout the Industry Topics of the Codification. ASU 2014-09 provides a five-step analysis of transactions to determine when and how revenue is recognized that consists of: i) identify the contract with the customer; ii) identify the performance obligations in the contract; iii) determine the transaction price; iv) allocate the transaction price to the performance obligations; and v) recognize revenue when or as each performance obligation is satisfied. Companies can transition to the requirements of this ASU either retrospectively or as a cumulative-effect adjustment as of the date of adoption, which was originally January 1, 2017 for the Company. In August 2015, the Financial Accounting Standards Board (FASB) issued ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date* (ASU 2014-14) that defers the effective date by one year, although it permits early adoption as of the original effective date. The Company is in the process of evaluating the impact to its financial position, results of operations, and cash flows of the adoption of ASU 2014-09.

In April 2015, the FASB issued ASU 2015-03, *Interest-Imputation of Interest (Subtopic 835-30)* (ASU 2015-03), which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The provisions of ASU 2015-03 are effective for fiscal years beginning after December 15, 2015, or January 1, 2016 for PGE, and interim periods within those fiscal years. Early adoption is permitted for financial statements that have not been previously issued. The provisions should be applied on a retrospective basis. Upon transition, an entity is required to comply with the applicable disclosures for a change in an accounting principle, which includes: i) the nature of and reason for the change in accounting principle; ii) the transition method; iii) a description of the prior-period information that has been retrospectively adjusted; and iv) the effect of the change on the financial statement line items. In August 2015, the FASB issued ASU 2015-15, *Interest-Imputation of Interest (Subtopic 835-30): Presentation of Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements-Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting (SEC Update) (ASU 2015-15),* which clarifies that the SEC staff would "not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of credit arrangement" given the lack of guidance on this topic in ASU 2015-03. PGE will adopt the amendments contained in ASU 2015-03 and 2015-15 on January 1, 2016, which is not expected to have a material impact on PGE's financial position, results of operation, or cash flows.

In May 2015, the FASB issued ASU 2015-07, *Fair Value Measurement (Topic 820), Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07), which removes the requirement to categorize within the fair value hierarchy investments for which fair value is measured using the net asset value per share practical expedient. The amendments also remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient. Instead, such disclosures are restricted only to investments that the entity has decided to measure using the practical expedient. This standard is effective for interim and annual periods beginning after December 15, 2015. PGE will adopt the amendments contained in ASU 2015-07 on January 1, 2016, which is not expected to have an impact on the Company's financial position, results of operations, or cash flows.

In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 330), Simplifying the Measurement of Inventory* (ASU 2015-11), which changes the measurement principle for inventory from the lower of cost or market to lower of cost and net realizable value. Net realizable value is defined as the "estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation." ASU 2015-11 eliminates the guidance that entities consider replacement cost or net realizable value less an approximately normal profit margin in the subsequent measurement of inventory when cost is determined on a first-in, first-out or average cost basis. The provisions of ASU 2015-11 are effective for public entities with fiscal years beginning after

December 15, 2016, or January 1, 2017 for PGE, and interim periods within those fiscal years. Early adoption is permitted. The Company is in the process of evaluating the impact to its financial position, results of operations, and cash flows of the adoption of ASU 2015-11.

In January 2016, the FASB issued ASU 2016-01, *Financial Instrument-Overall (Subtopic 825-10), Recognition and Measurement of Financial Assets and Financial Liabilities* (ASU 2016-01), which enhances the reporting model for financial instruments and related disclosures. The main provisions of the ASU will include: i) requirements to measure equity investments (except those accounted for under the equity method of accounting) at fair value with changes in fair value recognized in net income; ii) simplification of the impairment assessment of equity investments without readily determinable fair values; iii) eliminate the requirement to disclose the method(s) and significant assumptions used to estimate the fair value that is required to be disclosed for financial instruments measured at amortized cost on the balance sheet; iv) requirement to use the exit price notion when measuring the fair value of financial instruments for disclosure purposes; v) require an entity to present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk when the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments; and vi) require separate presentation of financial assets and financial liabilities by measurement category and form of financial asset on the balance sheet or footnotes. The provisions of ASU 2016-01 are effective for public entities with fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption is permitted, in certain circumstances. The Company is in the process of evaluating the impact to its financial position, results of operations, and cash flows of the adoption of ASU 2015-11.

NOTE 3: COMPARATIVE BALANCE SHEET COMPONENTS

Accumulated Provision for Uncollectible Accounts

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

	Years Ended December 31,	
	2015	**2014**
Balance as of beginning of year	$ 6	$ 6
Increase in provision	6	6
Amounts written off, less recoveries	(6)	(6)
Balance as of end of year	$ 6	$ 6

Trust Accounts

PGE maintains two trust accounts as follows, both of which are included in Other Special Funds in the Comparative Balance Sheet:

Nuclear decommissioning trust—Reflects assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) at the Trojan nuclear power plant (Trojan), which was closed in 1993. The Nuclear decommissioning trust includes amounts collected from customers less qualified expenditures plus any realized and unrealized gains and losses on the investments held therein. In 2014 and 2013, the Company received $6 million and $44 million, respectively, from the settlement of a legal matter concerning costs associated with the operation of the ISFSI. Those funds were deposited into the Nuclear decommissioning trust. For additional information concerning the legal matter, see Note 7, Asset Retirement Obligations. In anticipation of the refund of the settlement amount to customers over a three year period that began in 2015, those funds were withdrawn from the Nuclear decommissioning trust during 2015.

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	
	2015	2014	2015	2014
Cash equivalents	$ 18	$ 65	$ 1	$ —
Marketable securities, at fair value:				
Equity securities	—	—	5	6
Debt securities	22	25	1	—
Insurance contracts, at cash surrender value	—	—	26	26
	$ 40	$ 90	$ 33	$ 32

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.

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 Comparative Balance Sheet, for which it is practicable to estimate fair value as of December 31, 2015 and 2014, and then classifies these financial assets and liabilities based on a fair value hierarchy that is used to prioritize the inputs to the valuation techniques used to measure fair value. The three 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 the years ended December 31, 2015 and 2014, except those transfers from 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, 2015			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Nuclear decommissioning trust: (1)				
Money market funds	$ —	$ 18	$ —	$ 18
Debt securities:				
Domestic government	6	8	—	14
Corporate credit	—	8	—	8
Non-qualified benefit plan trust: (2)				
Money market funds	—	1	—	1
Equity securities:				
Domestic	3	2	—	5
International	—	—	—	—
Debt securities - domestic government	1	—	—	1
Assets from price risk management activities: (1) (3)				
Electricity	—	7	—	7
Natural gas	—	3	—	3
	$ 10	$ 47	$ —	$ 57
Liabilities - Liabilities from price risk management activities: (1) (3)				
Electricity	$ —	$ 28	$ 105	$ 133
Natural gas	—	144	14	158
	$ —	$ 172	$ 119	$ 291

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in Other Regulatory Assets or Other Regulatory Liabilities as appropriate.
(2) Excludes insurance policies of $26 million, which are recorded at cash surrender value.
(3) For further information, see Note 5, Price Risk Management.

	As of December 31, 2014			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust: (1)				
Money market funds	$ —	$ 65	$ —	$ 65
Debt securities:				
Domestic government	7	7	—	14
Corporate credit	—	11	—	11
Non-qualified benefit plan trust: (2)				
Equity securities:				
Domestic	4	1	—	5
International	1	—	—	1
Assets from price risk management activities: (1) (3)				
Electricity	—	4	1	5
Natural gas	—	2	—	2
	$ 12	$ 90	$ 1	$ 103
Liabilities - Liabilities from price risk management activities: (1) (3)				
Electricity	$ —	$ 32	$ 80	$ 112
Natural gas	—	95	21	116
	$ —	$ 127	$ 101	$ 228

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in Other Regulatory Assets or Other Regulatory Liabilities as appropriate.
(2) Excludes insurance policies of $26 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 as Other Special Funds in PGE's Comparative Balance Sheet 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 Comparative Balance Sheet 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 NVPC 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 forward commodity prices and interest rates. Substantially all of these inputs 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 commodity forwards, 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 commodity forwards, futures, and swaps.

Quantitative information regarding the significant, unobservable inputs used in the measurement of Level 3 assets and liabilities from price risk management activities is presented below:

Commodity Contracts	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit Low	Price per Unit High	Price per Unit Weighted Average
	(in millions)						
As of December 31, 2015:							
Electricity physical forward	$ —	$ 105	Discounted cash flow	Electricity forward price (per MWh)	$ 8.50	$ 84.47	$ 30.69
Natural gas financial swaps	—	14	Discounted cash flow	Natural gas forward price (per Dth)	2.06	3.70	2.54
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	9.98	27.36	19.26
	$ —	$ 119					
As of December 31, 2014:							
Electricity physical forward	$ —	$ 77	Discounted cash flow	Electricity forward price (per MWh)	$ 11.97	$ 122.72	$ 37.43
Natural gas financial swaps	—	21	Discounted cash flow	Natural gas forward price (per Dth)	2.88	4.86	3.41
Electricity financial futures	1	3	Discounted cash flow	Electricity forward price (per MWh)	11.97	39.26	27.88
	$ 1	$ 101					

The significant unobservable inputs used in the Company’s fair value measurement of price risk management assets and liabilities are long-term forward prices for commodity derivatives. For shorter term contracts, the Company employs the mid-point of the bid-ask spread of the market and these inputs are derived using observed transactions in active markets, as well as historical experience as a participant in those markets. These price inputs are validated against independent market data from multiple sources. For certain long term contracts, observable, liquid market transactions are not available for the duration of the delivery period. In such instances, the Company uses internally-developed price curves, which derive longer term prices and utilize observable data when available. When not available, regression techniques are used to estimate unobservable future prices. In addition, changes in the fair value measurement of price risk management assets and liabilities are analyzed and reviewed on a monthly basis by the Company.

The Company'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. Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Input	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)

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, 2015	Years Ended December 31, 2014
Net liabilities from price risk management activities as of beginning of year	$ 100	$ 139
Net realized and unrealized losses *	80	15
Settlements	—	(4)
Net transfers out of Level 3 to Level 2	(61)	(50)
Net liabilities from price risk management activities as of end of year	$ 119	$ 100
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 80	$ 12

* Includes nominal net realized losses in 2015 and $3 million in 2014.

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. During the years ended December 31, 2015 and 2014, there were no significant transfers into Level 3 from Level 2. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers in and transfers out of Level 3 at the end of the reporting period for all of its derivative instruments. Transfers from Level 2 to Level 1 for the Company's price risk management assets and liabilities do not occur as quoted prices are not available for identical instruments. As such, the Company's assets and liabilities from price risk management activities mature and settle as Level 2 fair value measurements.

Long-term debt is recorded at amortized cost in PGE's Comparative Balance Sheet. The fair value of the Company's First Mortgage Bonds (FMBs) and Pollution Control Revenue Bonds (PCBs) 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. The fair value of PGE's unsecured term bank loans was classified as Level 3 fair value measurement and was estimated based on the terms of the loans and the Company's creditworthiness. The significant unobservable inputs to the Level 3 fair value measurement included the interest rate and the length of the loan. The estimated fair value of the Company's unsecured term bank loans approximated their carrying value.

As of December 31, 2015, the carrying amount of PGE's long-term debt was $2,204 million and its estimated aggregate fair value was $2,455 million, classified as Level 2 in the fair value hierarchy. As of December 31, 2014, the carrying amount of PGE's long-term debt was $2,501 million and its estimated aggregate fair value was $2,901 million, consisting of $2,596 million, classified as Level 2 and $305 million classified as Level 3, respectively, in the fair value hierarchy.

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 Comparative Balance Sheet, 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's assets and liabilities from price risk management activities consist of the following (in millions):

	As of December 31,	
	2015	**2014**
Current assets:		
Commodity contracts:		
Electricity	$ 7	$ 4
Natural gas	3	2
Total current derivative assets	10	6
Noncurrent assets:		
Commodity contracts:		
Electricity	—	1
Total noncurrent derivative assets	—	1
Total derivative assets not designated as hedging instruments	$ 10	$ 7
Total derivative assets	$ 10	$ 7
Current liabilities:		
Commodity contracts:		
Electricity	$ 36	$ 54
Natural gas	94	52
Total current derivative liabilities	130	106
Noncurrent liabilities:		
Commodity contracts:		
Electricity	97	58
Natural gas	64	64
Total noncurrent derivative liabilities	161	122
Total derivative liabilities not designated as hedging instruments	$ 291	$ 228
Total derivative liabilities	$ 291	$ 228

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 2035, were as follows (in millions):

	As of December 31,			
	2015		**2014**	
Commodity contracts:				
Electricity	12	MWh	16	MWh
Natural gas	124	Dth	127	Dth
Foreign currency exchange	$ 7	Canadian	$ 7	Canadian

PGE has elected to report gross on the Comparative Balance Sheet the positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement. In the case of default on, or termination of, any contract under the master netting arrangements, these agreements provide for the net settlement of all related contractual obligations with a counterparty through a single payment. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral, such as letters of credit. As of December 31, 2015 and 2014, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $111 million and $72 million, respectively, for which PGE posted collateral of $14 million and $11 million, which consisted entirely of letters of credit. As of December 31, 2015, of the gross amounts included, $104 million was for electricity and $7 million was for natural gas compared to $55 million for electricity and $17 million for natural gas recognized as of December 31, 2014.

Net realized and unrealized losses on derivative transactions not designated as hedging instruments are classified in Purchased Power in the Statement of Income and were as follows (in millions):

	Years Ended December 31,	
	2015	**2014**
Commodity contracts:		
Electricity	$ 72	$ 13
Natural Gas	103	72
Foreign currency exchange	1	—

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, 2015 and 2014, $160 million and $83 million, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table presents the year in which the net unrealized loss recorded as of December 31, 2015 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2016	**2017**	**2018**	**2019**	**2020**	**Thereafter**	**Total**
Commodity contracts:							
Electricity	$ 29	$ 8	$ 7	$ 7	$ 6	$ 69	$ 126
Natural gas	91	50	12	2	—	—	155
Net unrealized loss	$ 120	$ 58	$ 19	$ 9	$ 6	$ 69	$ 281

PGE's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and Standard & 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. Certain other counterparties would 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, 2015 was $278 million, for which the Company had posted $80 million in collateral, consisting of $61 million in letters of credit and $19 million in cash. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2015, the cash requirement to either post as collateral or settle the instruments immediately would have been $255 million. As of December 31, 2015, PGE had posted an additional $14 million in cash collateral for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivatives is classified as Special Deposits on the Company's Comparative Balance Sheet.

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

	As of December 31,	
	2015	**2014**
Assets from price risk management activities:		
Counterparty A	59%	63%
Counterparty B	10	14
	69%	77%
Liabilities from price risk management activities:		
Counterparty C	36%	22%
Counterparty D	10	7
Counterparty E	10	9
Counterparty F	5	12
	61%	50%

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, 2015	As of December 31, 2014
Regulatory assets:			
Price risk management (2)	4 years	$ 280	$ 221
Pension and other postretirement plans (2)	(3)	239	247
Deferred income taxes (2)	(4)	89	89
Deferred broker settlements(2)	1 year	2	4
Deferred capital projects	1 year	—	19
Other (5)	Various	30	34
Total regulatory assets		$ 640	$ 614
Regulatory liabilities:			
Tro[jan decommissioning activities	3 years	33	57
Asset retirement obligations (6)	(4)	45	39
Other	Various	29	32
Total regulatory liabilities		$ 107	$ 128

(1) As of December 31, 2015.
(2) Does not include a return on investment.
(3) Recovery expected over the average service life of employees.
(4) Recovery expected over the estimated lives of the assets.
(5) Of the total other unamortized regulatory asset balances, a return is recorded on $29 million and $33 million as of December 31, 2015 and 2014, respectively.
(6) Included in rate base for ratemaking purposes.

As of December 31, 2015, PGE had regulatory assets of $30 million earning a return on investment at the following rates: i) $25 million earning a return by inclusion in rate base; ii) $4 million at the approved rate for deferred accounts under amortization, ranging from 1.47% to 1.93%, depending on the year of approval; and iii) $1 million at PGE’s 2015 cost of capital of 7.56%.

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 2011 GRC. The recovery of these project costs in customer prices began January 1, 2014 and was fully amortized as of December 31, 2015.

Trojan decommissioning activities represents proceeds received for the settlement of a legal matter concerning the reimbursement from the United States Department of Energy (USDOE) of certain monitoring costs incurred related to spent nuclear fuel at Trojan, as well as ongoing costs and collections associated with decommissioning activities. The USDOE settlement proceeds will be returned to customers over a three-year period that began January 1, 2015 and offset amounts previously collected from customers in relation to Trojan decommissioning activities.

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,	
	2015	**2014**
Trojan decommissioning activities	$ 43	$ 41
Utility Plant	97	64
Non-utility property	11	11
Asset retirement obligations	$ 151	$ 116

Trojan decommissioning activities represents the present value of future decommissioning costs for the plant, which ceased operation in 1993. The remaining decommissioning activities primarily consist of the long-term operation and decommissioning of the 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 USDOE facility is complete, which is not expected prior to 2034.

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, which holds a 67.5% ownership interest in Trojan, 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 sought approximately $112 million in damages incurred through 2009.

A trial before the U.S. Court of Federal Claims concluded in 2012, with the U.S. Court of Federal Claims issuing a judgment awarding certain damages to the Plaintiffs. In 2013, the Plaintiffs received $70 million for the settlement of this matter. The settlement agreement also provides for a process to submit claims for allowable costs for the period 2010 through 2016, and pursuant to this process the Plaintiffs received $9 million in 2014 for costs related to the 2010 through 2013 time period. The Company will seek recovery of costs under the current settlement agreement, as well as any subsequent extensions of the agreement to cover future periods.

PGE has received proceeds of $50 million related to its share in this legal matter, with $44 million received in 2013 and $6 million received in 2014. Such funds were deposited into the Nuclear decommissioning trust and recorded as a regulatory liability to offset amounts previously collected in relation to Trojan decommissioning activities. In December 2014, the OPUC issued an order on the Company's 2015 GRC, authorizing the return of the $50 million of proceeds received related to this legal matter to customers over a three-year period beginning January 1, 2015. In early 2015, a distribution was made from the Nuclear decommissioning trust in the amount of $50 million to be refunded to customers over the three year period that began January 1, 2015.

The ARO related to Trojan decommissioning activities was not impacted by the outcome of this legal matter because the proceeds received in connection with the settlement of this legal matter were for past Trojan decommissioning costs and this ARO reflects future Trojan decommissioning costs.

Utility Plant represents AROs that have been recognized for the Company's thermal and wind generation sites, distribution and transmission assets, the disposal of which is governed by environmental regulation. During 2015, the Company recorded an overall increase in AROs of $33 million, with the change comprised of an increase to revisions in estimated cash flows and incurred liabilities of $30 million, accretion of $4 million, and a reduction of $1 million due to settled liabilities.

In 2015 and 2014, PGE increased its ARO related to Boardman by $9 million and $7 million, respectively, due primarily to changes in timing of estimated settlements and due to the acquisition of additional interests in Boardman, with corresponding increases in the cost basis of the plant, included in Utility Plant, net on the Comparative Balance Sheet. For additional information regarding the Company's acquisition of additional interests in Boardman, see Note 15, Jointly-owned Plant.

The United States Environmental Protection Agency (EPA) published a final rule, effective October 19, 2015, that regulates Coal Combustion Residuals (CCRs) under the Resource Conservation and Recovery Act, Subtitle D. The rule imposes extensive new requirements, including location restrictions, design and operating standards, groundwater monitoring and corrective action requirements, and closure and post-closure care requirements on CCR impoundments and landfills that are located on active power plant sites and not closed. The requirements for covered CCR impoundments and landfills under the final rule include commencement or completion of closure activities generally between three and ten years from certain triggering events.

The Boardman coal-fired generating plant (Boardman) produces dry CCRs as a by-product. Disposal of the dry CCRs has historically occurred at an on-site landfill that is permitted and regulated by the state of Oregon under requirements similar to the final EPA rule. PGE has determined that it will continue use of the on-site landfill in compliance with the new rule, and the Company believes the final EPA rule will not have a material effect on operations at Boardman.

Colstrip utilizes wet scrubbers and a number of settlement ponds that will require upgrading or closure to meet the new regulatory requirements. The operator of Colstrip has provided an initial cost estimate related to the impacts of the final EPA rule. As a result, during 2015, the Company recorded an increase to the existing Colstrip AROs in the amount of $17 million, with a corresponding increase in the cost basis of the plant, included in Utility plant, net on the Comparative Balance Sheet. PGE plans to seek recovery in customer prices of the incremental costs associated with the final EPA rule.

In 2015, PGE also recorded AROs totaling $4 million related to the Company's Beaver natural gas-fired generating plant (Beaver) and Carty.

Non-utility property primarily represents AROs 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,	
	2015	2014
Balance as of beginning of year	$ 116	$ 100
Liabilities incurred	2	15
Liabilities settled	(4)	(3)
Accretion expense	7	6
Revisions in estimated cash flows	30	(2)
Balance as of end of year	$ 151	$ 116

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, approximately $4 million annually, with an equal amount recorded in Total Utility Operating Expenses.

PGE maintains a separate trust account, Nuclear decommissioning trust, which is included in Other Special Funds in the Comparative Balance Sheet, for funds collected from customers through prices to cover the cost of Trojan decommissioning activities. See "*Trust Accounts*" in Note 3, Comparative 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: CREDIT FACILITIES

As of December 31, 2015, PGE had a $500 million credit facility scheduled to expire in November 2019.

Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, as backup for commercial paper borrowings, and 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. The revolving credit facility contains provisions for two, one-year extensions subject to approval by the banks, requires annual fees based on PGE's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits indebtedness, as defined in the agreement, to 65% of total capitalization. As of December 31, 2015, PGE was in compliance with this covenant with a 49.5% debt to total capital 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 facility.

PGE classifies any borrowings under the revolving credit facility and outstanding commercial paper as Notes Payable in the Comparative Balance Sheet.

Under the credit facility, as of December 31, 2015, PGE had $6 million of commercial paper outstanding and no borrowings or letters of credit issued. As of December 31, 2015, the aggregate unused available credit capacity under the revolving credit facility was $494 million.

In addition, PGE has four letter of credit facilities that provide a total of $160 million capacity under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, $108 million of letters of credit was outstanding, as of December 31, 2015.

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt in an aggregate amount up to $900 million through February 6, 2018.

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

	Years Ended December 31,	
	2015	2014
Average daily amount of Notes Payable outstanding	$ —	$ —
Weighted daily average interest rate *	0.6%	—%
Maximum amount outstanding during the year	$ 11	$ —

* 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,	
	2015	2014
First Mortgage Bonds, rates range from 3.46% to 9.31%, with a weighted average rate of 5.29% in 2015 and 5.42% in 2014, due at various dates through 2048	$ 2,083	$ 2,075
Unsecured term bank loans, rates range from 0.86% to 0.93%, due October 2015	—	305
Pollution Control Revenue Bonds, 5% rate, due 2033	142	142
Pollution Control Revenue Bonds owned by PGE	(21)	(21)
Total long-term debt	$ 2,204	$ 2,501

First Mortgage Bonds and Unsecured term bank loans—During 2015, PGE issued a total of $145 million of FMBs and repaid long-term debt, inclusive of the Unsecured term bank loans, in an aggregate amount of $442 million, as follows:

- In January, issued $75 million of 3.55% Series FMBs due 2030 and repaid $70 million of 3.46% Series FMBs;
- In February, repaid $50 million of long-term bank loans;
- In May, issued $70 million of 3.5% Series FMBs due 2035 and repaid $67 million of 6.80% Series FMBs, due January 2016;
- In June, repaid $200 million of long-term bank loans; and
- In July, repaid the remaining outstanding balance of long-term debt bank loans in the amount of $55 million.

The Indenture securing PGE's outstanding FMBs constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property. Interest is payable semi-annually on FMBs.

In January 2016, the Company issued $140 million of 2.51% Series FMBs due 2021 and repaid $58 million of 3.81% Series FMBs, due in 2017 and $75 million of 5.80% series FMBs due in 2018.

During 2014, PGE obtained four unsecured term bank loans pursuant to a credit agreement in an aggregate principal amount of $305 million. The credit agreement was set to expire October 30, 2015, at which time any amounts outstanding under the term loans were to become due and payable. The Company fully repaid these term loans early with the final payment made in July 2015.

Pollution Control Revenue Bonds—The Company has the option to remarket through 2033 the $21 million of PCBs held by PGE as of December 31, 2015. At the time of any remarketing, the Company 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 PCBs could be backed by FMBs or a bank letter of credit depending on market conditions. Interest is payable semi-annually on PCBs.

As of December 31, 2015, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:		
2016	$	—
2017		58
2018		75
2019		300
2020		—
Thereafter		1,771
	$	2,204

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. No changes were made to the benefits provided to existing participants when the plan was closed to new employees.

The assets of the pension plan are held in a trust and are comprised of equity and debt instruments, 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 2015 or 2014. No contributions to the pension plan are expected in 2016.

In 2014, the Company offered certain eligible participants of the pension plan the option to select a lump sum distribution. As a result of this offering, PGE made lump sum distributions totaling $16 million on July 1, 2014.

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. 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 Other Special Funds in PGE's Comparative Balance Sheet are as follows as of December 31 (in millions):

	2015			2014		
	NQBP	**Other NQBP**	**Total**	**NQBP**	**Other NQBP**	**Total**
Non-qualified benefit plan trust	$ 15	$ 18	$ 33	$ 15	$ 17	$ 32
Non-qualified benefit plan liabilities	27	81	108	27	80	107

See "*Trust Accounts*" in Note 3, Comparative 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,			
	2015		2014	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	67%	67%	66%	67%
Debt securities	33	33	34	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	60%	64%	66%	67%
Debt securities	40	36	34	33
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	15%	14%	19%	13%
Debt securities	7	8	1	7
Insurance contracts	78	78	80	80
Total	100%	100%	100%	100%

* The target for the Defined Benefit Pension 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):

	Level 1	Level 2	Level 3	Total
As of December 31, 2015:				
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 5	$ —	$ 5
Equity securities:				
Domestic	$ 44	$ 132	$ —	$ 176
International	—	170	—	170
Debt securities:				
Domestic government and corporate credit	—	177	—	177
Private equity funds	—	—	22	22
	$ 44	$ 484	$ 22	$ 550
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 7	$ —	$ 7
Equity securities:				
Domestic	—	10	—	10
International	8	—	—	8
Debt securities—Domestic government	—	5	—	5
	$ 8	$ 22	$ —	$ 30
As of December 31, 2014:				
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 6	$ —	$ 6
Equity securities:				
Domestic	$ 42	$ 146	$ —	$ 188
International	—	171	—	171
Debt securities:				
Domestic government and corporate credit	—	197	—	197
Private equity funds	—	—	29	29
	$ 42	$ 520	$ 29	$ 591
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 6	$ —	$ 6
Equity securities:				
Domestic	10	1	—	11
International	10	—	—	10
Debt securities—Domestic government	5	—	—	5
	$ 25	$ 7	$ —	$ 32

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 classified as Level 1 securities as pricing inputs are based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and NYSE. 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.

Changes in the fair value of assets held by the pension plan classified as Level 3 in the fair value hierarchy, which consists of Private equity funds, were as follows (in millions):

	Years Ended December 31,	
	2015	**2014**
Level 3 balance as of beginning of year	$ 29	$ 31
Unrealized (losses) gains, net	(2)	2
Realized gains, net	4	3
Sales, net	(9)	(7)
Level 3 balance as of end of year	$ 22	$ 29

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, 2015 and 2014. 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	
	2015	2014	2015	2014	2015	2014
Benefit obligation:						
As of January 1	$ 777	$ 705	$ 83	$ 77	$ 27	$ 24
Service cost	18	15	2	2	—	—
Interest cost	31	34	3	4	1	1
Participants’ contributions	—	—	2	1	—	—
Actuarial (gain) loss	(31)	72	(4)	4	1	5
Contractual termination benefits	—	—	1	1	—	—
Benefit payments	(35)	(48)	(6)	(6)	(2)	(3)
Administrative expenses	(2)	(1)	—	—	—	—
As of December 31	$ 758	$ 777	$ 81	$ 83	$ 27	$ 27
Fair value of plan assets:						
As of January 1	$ 591	$ 596	$ 32	$ 32	$ 15	$ 16
Actual return on plan assets	(4)	44	(2)	1	—	1
Company contributions	—	—	4	4	2	1
Participants’ contributions	—	—	2	1	—	—
Benefit payments	(35)	(48)	(6)	(6)	(2)	(3)
Administrative expenses	(2)	(1)	—	—	—	—
As of December 31	$ 550	$ 591	$ 30	$ 32	$ 15	$ 15
Unfunded position as of December 31	$ (208)	$ (186)	$ (51)	$ (51)	$ (12)	$ (12)
Accumulated benefit plan obligation as of December 31	$ 681	$ 691	N/A	N/A	$ 27	$ 27
Classification in Comparative Balance Sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 15	$ 15
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(208)	(186)	(51)	(51)	(25)	(25)
Net liability	$ (208)	$ (186)	$ (51)	$ (51)	$ (12)	$ (12)
Amounts included in comprehensive income:						
Net actuarial loss	$ 13	$ 67	$ —	$ 5	$ 1	$ 5
Amortization of net actuarial loss	(20)	(17)	(1)	(1)	(1)	(1)
Amortization of prior service cost	—	—	(1)	(1)	—	—
	$ (7)	$ 50	$ (2)	$ 3	$ —	$ 4
Amounts included in AOCL*:						
Net actuarial loss	$ 228	$ 236	$ 9	$ 10	$ 13	$ 13
Prior service cost	—	—	1	1	—	—
	$ 228	$ 236	$ 10	$ 11	$ 13	$ 13

Assumptions used:						
Discount rate for benefit obligation	4.36%	4.02%	3.90%-4.45%	3.07%-4.10%	4.36%	4.02%
Discount rate for benefit cost	4.02%	4.84%	3.07%-4.10%	3.46%-4.96%	4.02%	4.84%
Weighted average rate of compensation increase for benefit obligation	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Weighted average rate of compensation increase for benefit cost	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Long-term rate of return on plan assets for benefit obligation	7.50%	7.50%	6.29%	6.37%	N/A	N/A
Long-term rate of return on plan assets for benefit cost	7.50%	7.50%	6.37%	6.46%	N/A	N/A

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to Other Regulatory Assets due to the future recoverability from retail customers. Accordingly, as of the Comparative Balance Sheet date, such amounts are included in Other 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**	
	2015	**2014**	**2015**	**2014**	**2015**	**2014**
Service cost	$ 18	$ 15	$ 2	$ 2	$ —	$ —
Interest cost on benefit obligation	31	34	3	4	1	1
Expected return on plan assets	(40)	(39)	(2)	(2)	—	—
Amortization of prior service cost	—	—	1	1	—	—
Amortization of net actuarial loss	20	17	1	1	1	1
Net periodic benefit cost	$ 29	$ 27	$ 5	$ 6	$ 2	$ 2

PGE estimates that $16 million will be amortized from AOCL into net periodic benefit cost in 2016, consisting of a net actuarial loss of $14 million for pension benefits, $1 million for non-qualified benefits, and $1 million for prior service costs for other postretirement benefits. Amounts related to the pension and other postretirement benefits are offset with the amortization of the corresponding regulatory asset.

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					
	2016	**2017**	**2018**	**2019**	**2020**	**2021 - 2025**
Defined benefit pension plan	$ 37	$ 38	$ 40	$ 41	$ 42	$ 226
Other postretirement benefits	5	5	5	5	5	26
Non-qualified benefit plans	2	2	2	3	2	10
Total	$ 44	$ 45	$ 47	$ 49	$ 49	$ 262

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 2015, 6.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2016, decreasing to 6.0% in 2017, then decreasing 0.25% per year thereafter, reaching 5% in 2021; and
- For 2014, 7% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2015, 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 the majority of bargaining employees who are subject to the International Brotherhood of Electrical Workers Local 125 agreements the Company contributes an additional 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 $17 million in 2015 and $16 million in 2014.

NOTE 11: INCOME TAXES

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

	Years Ended December 31, 2015	Years Ended December 31, 2014
Current:		
Federal	$ 4	$ 20
State and local	1	2
	5	22
Deferred:		
Federal	26	26
State and local	14	13
	40	39
Income tax expense	$ 45	$ 61

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, 2015	Years Ended December 31, 2014
Federal statutory tax rate	35.0%	35.0%
Federal tax credits	(19.0)	(11.4)
State and local taxes, net of federal tax benefit	4.2	3.9
Flow through depreciation and cost basis differences	—	(2.3)
Other	0.5	0.8
Effective tax rate	20.7%	26.0%

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

	As of December 31,	
	2015	**2014**
Accumulated Deferred Income Tax Assets:		
Employee benefits	$ 171	$ 161
Price risk management	116	91
Regulatory liabilities	42	48
Tax credits	46	13
Depreciation and amortization	(23)	(6)
Other	18	17
Total Accumulated Deferred Income Tax Assets	370	324
Accumulated Deferred Income Tax Liabilities:		
Depreciation and amortization	758	686
Regulatory assets	221	211
Price Risk Management	4	3
Employee benefits	1	1
Other	18	15
Total Accumulated Deferred Income Tax Liabilities	1,002	916
Accumulated Deferred Income Tax Liability, net	$ (632)	$ (592)

As of December 31, 2015, PGE has federal and state tax credit carryforwards of $42 million and $4 million, respectively, which will expire at various dates from 2023 through 2035.

PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2015 and 2014 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2015 and 2014, PGE had no unrecognized tax benefits.

PGE and its subsidiaries file federal income tax returns, state income tax returns in certain jurisdictions, including Oregon, California, Montana, and returns in certain local jurisdictions. The Internal Revenue Service (IRS) has completed its examination of all tax years through 2010 and all issues were resolved related to those years. The Company does not believe that any open tax years for federal or state income taxes could result in any adjustments that would be significant to the financial statements.

The Protecting Americans from Tax Hikes Act of 2015 (PATH) was signed into law on December 18, 2015. Among other items, the PATH extended provisions for bonus depreciation and production tax credits through 2019, inclusive of certain phase-down schedules. In the event PGE qualifies for future production tax credits related to the construction of new wind generation facilities or deems the application of bonus depreciation favorable, the Company will consider utilizing some of the PATH's extended provisions. As of December 31, 2015, no provision materially impacts the Company's current financial position.

NOTE 12: EQUITY-BASED PLANS

Equity Forward Sale Agreement

PGE entered into an equity forward sale agreement (EFSA) in connection with a public offering of 11,100,000 shares of its common stock in June 2013. In connection with such public offering, the underwriters exercised their over-allotment option in full and PGE issued 1,665,000 shares of its common stock for net proceeds of $47 million. PGE received proceeds from the sale of common stock when the EFSA was physically settled (described below), and at that time PGE issued new shares of common stock and recorded the proceeds in equity. In the third quarter of 2013, the Company issued 700,000 shares of its common stock pursuant to the EFSA for net proceeds of $20 million. During the second quarter 2015, PGE physically settled in full the EFSA by issuing 10,400,000 shares of common PGE common stock in exchange for cash of $271 million.

Prior to settlement, the potentially issuable shares pursuant to the EFSA were reflected in PGE’s diluted earnings per share calculations using the treasury stock method. Under this method, the number of shares of PGE’s common stock used in calculating diluted earnings per share for a reporting period were increased by the number of shares, if any, that would be issued upon physical settlement of the EFSA less the number of shares that could have been purchased by PGE in the market with the proceeds received from issuance (based on the average market price during that reporting period).

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, 2015, there were 397,265 shares available for future issuance pursuant to the ESPP.

Dividend Reinvestment and Direct Stock Purchase Plan

PGE has a Dividend Reinvestment and Direct Stock Purchase Plan (DRIP), 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, 2015, there were 2,478,086 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 (RSUs) with time-based vesting conditions (time-based RSUs) and performance-based vesting conditions (performance-based RSUs) to non-employee directors, officers and certain key employees. Service requirements generally must be met for RSUs to vest. For each grant, the number of RSUs is determined by dividing the specified award amount for each grantee by the closing stock price on the date of grant. RSU activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2013	431,090	26.31
Granted	203,410	31.49
Forfeited	(12,278)	29.90
Vested	(158,329)	24.95
Outstanding as of December 31, 2014	463,893	28.96
Granted	181,797	34.77
Forfeited	(14,988)	34.10
Vested	(187,709)	25.82
Outstanding as of December 31, 2015	442,993	32.84

A total of 4,687,500 shares of common stock were registered for future issuance under the Plan, of which 3,443,904 shares remain available for future issuance as of December 31, 2015.

Outstanding RSUs 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 RSUs. 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-based RSUs) 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.

Time-based RSUs 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. The fair value of time-based RSUs is measured based on the closing price of PGE common stock on the date of grant and charged to compensation expense on a straight-line basis over the requisite service period for the entire award. The total value of time-based RSUs vested was less than $1 million for the years ended December 31, 2015 and 2014.

Performance-based RSUs vest if performance goals are met at the end of a three-year performance period. For grants prior to March 5, 2013, such goals include return on equity relative to allowed return on equity, and regulated asset base growth. Grants on and after March 5, 2013 are based on three equally-weighted metrics: return on equity relative to allowed return on equity; regulated asset growth; and a relative total shareholder return (TSR) of PGE’s common stock as compared to the Edison Electric Institute Regulated Index (EEI Index) during the performance period. Vesting of performance-based RSUs 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.

For the return on equity and regulated asset base growth portions of the performance-based RSUs, fair value is measured based on the closing price of PGE common stock on the date of grant. For the TSR portion of the performance-based RSUs, fair value is determined using a Monte Carlo simulation model utilizing actual information for the common shares of PGE and its peer group for the period from the beginning of the performance period to the grant date and estimated future stock volatility over the remaining performance period. The fair value of stock-based compensation related to the TSR component of performance-based RSUs was determined using the Monte Carlo model and the following weighted average assumptions:

	2015	2014
Risk-free interest rate	1.0%	0.6%
Expected dividend yield	—%	—%
Expected term (in years)	3.0	3.0
Volatility	13.2% - 19.2%	12.4% - 23.0%

The fair value of performance-based RSUs is charged to compensation expense on a straight-line basis over the requisite service period for the entire award based on the number of shares expected to vest. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the weighted average vesting of 130.1% and 132.4% of awarded performance-based RSUs for the respective 2015 and 2014 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $4 million for the year ended December 31, 2015 and $3 million for the year ended 2014, respectively.

Stock-based compensation was $6 million for the years ended December 31, 2015 and 2014, which is included in Administrative and General Expenses in the Statement of Income. Such amounts differ from those reported in Other Paid-in Capital for Stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The Company withholds a portion of the vested shares for the payment of income taxes on behalf of the 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 $2 million in 2015 and $1 million in 2014, which is not included in Administrative and General Expenses in the Statement of Income.

As of December 31, 2015, unrecognized stock-based compensation expense was $6 million, of which approximately $4 million and $2 million is expected to be expensed in 2016 and 2017, respectively. No stock-based compensation costs have been capitalized and the Plan had no material impact on cash flows for the years ended December 31, 2015 or 2014.

NOTE 14: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2015, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2016	**2017**	**2018**	**2019**	**2020**	**Thereafter**	**Total**
Capital and other purchase commitments	$ 85	$ 2	$ 2	$ 2	$ 9	$ 27	$ 127
Purchased power and fuel:							
Electricity purchases	226	204	147	150	190	852	1,769
Capacity contracts	26	6	6	5	4	16	63
Public utility districts	6	5	5	1	1	12	30
Natural gas	67	41	38	37	32	221	436
Coal and transportation	14	11	5	5	—	—	35
Operating leases	10	10	9	7	6	180	222
Total	$ 434	$ 279	$ 212	$ 207	$ 242	$ 1,308	$ 2,682

Capital and other purchase commitments—Certain commitments have been made for 2016 and beyond that include those related to hydro licenses, upgrades to generating, distribution, and transmission facilities, 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 2049, and power capacity contracts through 2024. In addition to the power purchase contracts with counterparties presented in the table, PGE has power sale contracts with counterparties of approximately $33 million that settle as follows: $15 million in 2016; $11 million in 2017, and $7 million in 2018.

Public utility districts—PGE has long-term power purchase agreements with certain public utility districts in the state of Washington and with the City of Portland, Oregon. Under the agreements, 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, 2015	PGE's Share as of December 31, 2015		Contract Expiration	PGE Cost, including Debt Service	
		Output	Capacity (in MW)		2015	2014
Priest Rapids and Wanapum	$ 1,191	8.6%	163	2052	$ 18	$ 14
Wells	207	19.4	150	2018	10	10
Portland Hydro	2	100.0	36	2017	2	4

The agreements for Priest Rapids and Wanapum and Wells 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. 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 contracts for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities. In addition to the gas purchase contracts with counterparties presented in the table, PGE has gas sale contracts with counterparties of approximately $2 million that settle in 2016. The Company also has a natural gas storage agreement for the purpose of fueling the Company's natural gas-fired generating plants (Port Westward Unit 1 (PW1), PW2, and Beaver).

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 2020.

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 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, which expires in 2096 and covers the location of PW1, PW2, and Beaver. Rent expense was $10 million in 2015 and $11 million in 2014.

The future minimum operating lease payments presented is net of sublease income of: $4 million in 2016; and $3 million in each of 2017, 2018, 2019 and 2020. Sublease income was $3 million in 2015 and 2014, respectively.

Guarantees

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, 2015, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the Comparative Balance Sheet with respect to these indemnities.

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 Expenses in the Statement of Income.

In 1985, PGE sold a 15% undivided interest in Boardman and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. PGE assumed responsibility for the ARO related to that 15% interest in Boardman in the amount of $7 million. The acquisition of the 15% interest in Boardman increased the Company's ownership share from 65% to 80% on December 31, 2013.

On December 31, 2014, PGE acquired an additional 10% interest in Boardman from another co-owner, whereby the Company received net cash of $8 million from the co-owner to assume the net liabilities associated with the ownership of this 10% interest. In connection with this transaction, PGE recorded Utility Plant of $7 million, inventory of $4 million, an ARO of $7 million, a regulatory liability of $6 million to be returned to customers over a two year period that began in 2015, a regulatory liability of $4 million related to future additional decommissioning and environmental costs, and deferred revenue of $2 million. The acquisition of the 10% interest in Boardman increased the Company's ownership share from 80% to 90%.

As of December 31, 2015, 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	90.00%	1980	$ 678	$ 541	$ —
Colstrip	20.00	1986	519	337	4
Pelton/Round Butte	66.67	1958 / 1964	244	58	5
Total			$ 1,441	$ 936	$ 9

* Excludes AROs 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 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.

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 circumstances in which 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 Class Actions

In 1993, PGE closed the Trojan nuclear power plant (Trojan) and sought full recovery of, and a rate of 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 rate of 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 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the matter to the OPUC for reconsideration.

In 2008, the OPUC issued an order (2008 Order) that required PGE to provide refunds of $33 million, including interest, which were completed in 2010. Following appeals, the 2008 Order was upheld by the Oregon Court of Appeals in February 2013 and by the Oregon Supreme Court (OSC) in October 2014.

In 2003, in two separate legal proceedings, lawsuits were filed in Marion County Circuit Court (Circuit Court) against PGE 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 in Trojan.

In August 2006, the OSC issued a ruling ordering the abatement of the class action proceedings. The OSC concluded that the OPUC had primary jurisdiction to determine what, if any, remedy could 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 OSC 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 OSC added that, if the OPUC determined that it cannot provide a remedy, the court system may have a role to play. The OSC also ruled that the plaintiffs retain the right to return to the Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings. In October 2006, the Circuit Court abated the class actions in response to the ruling of the OSC.

In June 2015, based on a motion filed by PGE, the Circuit Court lifted the abatement. PGE has filed a motion for summary judgment dismissing the lawsuits. On July 27, 2015, the Circuit Court heard oral argument on the Company’s motion for Summary Judgment. The court has yet to issue a decision on the motion. Following oral argument on PGE’s motion for summary judgment, the plaintiffs moved to amend the complaints. PGE opposed the request to amend and the Court has not yet issued its decision.

PGE believes that the October 2014 OSC decision has reduced the risk of a loss to the Company in excess of the amounts previously recorded and discussed above. However, because the class actions remain pending, management believes that it is reasonably possible that such a loss to the Company could result. As these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine the amount of any such loss.

Pacific Northwest Refund Proceeding

In response to the Western energy crisis of 2000-2001, the FERC initiated, beginning in 2001, a series of proceedings to determine whether refunds are warranted for bilateral sales of electricity in the Pacific Northwest wholesale spot market during the period December 25, 2000 through June 20, 2001. In an order issued in 2003, the FERC denied refunds. Various parties appealed the order to the Ninth Circuit Court of Appeals (Ninth Circuit) and, on appeal, the Ninth Circuit remanded the issue of refunds to the FERC for further consideration.

On remand, in 2011 and thereafter, the FERC issued several procedural orders that established an evidentiary hearing, defined the scope of the hearing, expanded the refund period to include January 1, 2000 through December 24, 2000 for certain types of claims, and described the burden of proof that must be met to justify abrogation of the contracts at issue and the imposition of refunds. Those orders included a finding by the FERC 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 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. The FERC also held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Refund proponents appealed these procedural orders at the Ninth Circuit. On December 17, 2015, the Ninth Circuit held that the FERC reasonably applied the *Mobile-Sierra* presumption to the class of contracts at issue in the proceedings and dismissed evidentiary challenges related to the scope of the proceeding. Plaintiffs on behalf of CERS filed a request for rehearing on February 1, 2016.

In response to the evidence and arguments presented during the hearing, in May 2015, the FERC issued an order finding that the refund proponents had failed to meet the *Mobile-Sierra* burden with respect to all but one respondent. In December 2015, the FERC denied all requests for rehearing of its order. With respect to the remaining respondent, FERC ordered additional proceedings, and a January 2016 revised initial decision has now recommended that certain contracts by such respondent be subject to refund.

The Company has settled all of the direct claims asserted against it in the proceedings for an immaterial amount. The settlements and associated FERC orders have not fully eliminated the potential for so-called “ripple claims,” which have been described by the FERC as “sequential claims against a succession of sellers in a chain of purchases that are triggered if the last wholesale purchaser in the chain is entitled to a refund.” However, the remaining respondent subject to the revised initial decision has stated on the record that it will not pursue ripple claims, and on February 1, 2016, the Acting Chief Administrative Law Judge issued an order holding that the issue of ripple claims is terminated for purposes of Phase II of these proceedings. Therefore, unless the current FERC orders are overturned or modified on appeal, the Company does not believe that it will incur any material loss in connection with this matter.

Management cannot predict the outcome of the various pending appeals and remands concerning this matter. If, on rehearing, appeal, or subsequent remand, the Ninth Circuit or the FERC were to reverse previous FERC rulings on liability or find that a market-wide remedy is appropriate, it is possible that additional refund claims could be asserted against the Company. However, management cannot predict, under such circumstances, which contracts would be subject to refunds, the basis on which refunds would be ordered, or how such refunds, if any, would be calculated. Further, management cannot predict whether any current respondents, if ordered to make refunds, would pursue additional refund claims against their suppliers, and, if so, what the basis or amounts of such potential refund claims against the Company would be. 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 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. In August 2015, the EPA substantially revised the draft FS as submitted by the LWG and issued its own draft FS which is currently in the process of undergoing further consideration and comment. The draft FS, along with the RI, is expected to provide the framework for the EPA to determine a clean-up remedy for Portland Harbor that will be documented in a Record of Decision (ROD).

The EPA's draft FS evaluates several alternative clean-up approaches, which would take from four to 18 years with the present value of estimated costs ranging from $800 million to $2.4 billion, depending on the selected remedial action levels and the choice of remedy. While the revised draft FS aids in the development of a proposed plan to remediate Portland Harbor, 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. In November 2015, the EPA proposed its preferred alternative remedy to the National Remedy Review Board (NRRB) for comment. The EPA's preferred alternative has an estimated present value cost of $1.5 billion and would take approximately seven years to complete. The EPA anticipates it will release, for public review and comment, a Proposed Cleanup Plan in the Spring of 2016. The Company currently expects the EPA to issue a determination of its preferred remedy in a final ROD in late 2016, however responsibility for funding and implementing the EPA's selected remedy is not expected to be known for some time. PGE is participating in a voluntary process to establish and develop allocation of costs.

Where injuries to natural resources have occurred as a result of releases of hazardous substances, federal and state natural resource trustees may seek to recover for damages at such sites, which is referred to as natural resource damages. As it relates to the Portland Harbor, PGE has been participating in the Portland Harbor Natural Resource Damages assessment (NRDA) process. The EPA does not manage NRDA activities, but provides claims information and coordination support to the Natural Resource Damages (NRD) trustees. Damage assessment activities are typically conducted by a Trustee Council made up of the trustee entities for the site, and claims are not concluded until a final remedy for clean-up has been settled. The Portland Harbor NRD trustees are the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, the state of Oregon, and certain tribal entities.

After the claimed damages at a site are assessed, the NRD trustees may seek to negotiate legal settlements or take other legal actions against the parties responsible for the damages. Funds from such settlements must be used to restore injured resources and may also compensate the trustees for costs incurred in assessing the damages. It is uncertain what portion, if any, PGE may be held responsible related to Portland Harbor.

As discussed above, significant uncertainties still remain concerning the precise boundaries for clean-up, the assignment of responsibility for clean-up costs, the final selection of a proposed remedy by the EPA, the amount of natural resource damages, and the agreement of allocation of costs amongst PRPs. Although it is probable that the Company's share of these costs could be material, the Company does not currently have sufficient information to reasonably estimate the amount, or range, of its potential costs for investigation or remediation of the Portland Harbor site and NRDA. The Company plans to seek recovery of any costs resulting from the Portland Harbor proceeding through regulatory recovery in customer prices and through claims under insurance policies.

Alleged Violation of Environmental Regulations at Colstrip

In July 2012, PGE received a Notice of Intent to Sue (Notice) for violations of the Clean Air Act (CAA) at Colstrip Steam Electric Station (CSES) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other CSES co-owners, including Talen Montana, LLC, the operator of CSES. PGE has a 20% ownership interest in Units 3 and 4 of CSES. The Notice alleges certain violations of the CAA, including New Source Review, Title V, and opacity requirements, and stated that the Sierra Club and MEIC would: 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.

The Sierra Club and MEIC asserted that the CSES owners violated the Title V air quality operating permit during portions of 2008 and 2009 and 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 Sierra Club and MEIC also asserted violations of opacity provisions of the CAA.

On March 6, 2013, the Sierra Club and MEIC sued the CSES co-owners, including PGE, for these and additional alleged violations of various environmental related regulations. The plaintiffs are seeking relief that includes an injunction preventing the co-owners from operating CSES except in accordance with the CAA, the Montana State Implementation Plan, and the plant's federally enforceable air quality permits. In addition, plaintiffs are seeking civil penalties against the co-owners including $32,500 per day for each violation occurring through January 12, 2009, and $37,500 per day for each violation occurring thereafter.

In May 2013, the defendants filed a motion to dismiss 36 of 39 claims alleged in the complaint. In September 2013, the plaintiffs filed a motion for partial summary judgment regarding the appropriate method of calculating emissions increases. Also in September 2013, the plaintiffs filed an amended complaint that withdrew Title V and opacity claims, added claims associated with two 2011 projects, and expanded the scope of certain claims to encompass approximately 40 additional projects. In July 2014, the court denied the defendants' motion to dismiss and the plaintiffs' motion for partial summary judgment.

In August 2014, the plaintiffs filed a second amended complaint to which the defendants' response was filed in September 2014. The second amended complaint continues to seek injunctive relief, declaratory relief, and civil penalties for alleged violations of the federal Clean Air Act. The plaintiffs state in the second amended complaint that it was filed, in part, to comply with the court's ruling on the defendants' motion to dismiss and plaintiffs' motion for partial summary judgment. Discovery in this matter is complete. The parties filed various summary judgment motions during the summer of 2015. Oral argument on those motions occurred on December 1, 2015. On or about December 31, 2015, the Magistrate Judge issued Findings and Recommendations that, if adopted by the trial court, would result in dismissal of several of the plaintiffs' claims. The case is currently set for trial on May 6, 2016.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties concerning this matter, PGE cannot predict the outcome, estimate a range of potential loss, or determine whether it would have a material impact on the Company.

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 business, which may result in judgments against the Company. Although management currently believes that resolution of such matters, individually and in the aggregate, will not have a material impact 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				(5,061,980)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(2,641,424)
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				(2,641,424)
5	Balance of Account 219 at End of Preceding Quarter/Year				(7,703,404)
6	Balance of Account 219 at Beginning of Current Year				(7,703,404)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(218,991)
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				(218,991)
10	Balance of Account 219 at End of Current Quarter/Year				(7,922,395)

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 2015/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	(808)		(5,062,788)	[redacted]	[redacted]
2			(2,641,424)	[redacted]	[redacted]
3				[redacted]	[redacted]
4			(2,641,424)	175,401,893	172,760,469
5	(808)		(7,704,212)	[redacted]	[redacted]
6	(808)		(7,704,212)	[redacted]	[redacted]
7			(218,991)	[redacted]	[redacted]
8				[redacted]	[redacted]
9			(218,991)	172,147,958	171,928,967
10	(808)		(7,923,203)	[redacted]	[redacted]

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

Comprised of the net amount of the actuarial valuation of $4,402,374 of non-qualifed benefit plans net of taxes of $(1,7960,950).

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

Comprised of the net amount of the actuarial valuation of $364,985 of non-qualified benefit plans net of taxes of $(145,994).

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 2015/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)	8,717,935,968	8,717,935,968
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	8,717,935,968	8,717,935,968
9	Leased to Others		
10	Held for Future Use	4,638,631	4,638,631
11	Construction Work in Progress	545,045,342	545,045,342
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	9,267,619,941	9,267,619,941
14	Accum Prov for Depr, Amort, & Depl	4,094,637,726	4,094,637,726
15	Net Utility Plant (13 less 14)	5,172,982,215	5,172,982,215
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,867,871,335	3,867,871,335
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	226,766,391	226,766,391
22	Total In Service (18 thru 21)	4,094,637,726	4,094,637,726
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)	4,094,637,726	4,094,637,726

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 2015/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
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	179,823,413	2,623,207
4	(303) Miscellaneous Intangible Plant	297,741,043	78,935,903
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	477,564,456	81,559,110
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,161,715	
9	(311) Structures and Improvements	255,817,013	118,772
10	(312) Boiler Plant Equipment	585,145,082	3,156,242
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	188,445,850	825,386
13	(315) Accessory Electric Equipment	55,159,472	111,019
14	(316) Misc. Power Plant Equipment	14,809,756	29,648
15	(317) Asset Retirement Costs for Steam Production	37,889,981	26,380,362
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,141,428,869	30,621,429
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	6,047,627	
28	(331) Structures and Improvements	51,134,536	2,201,455
29	(332) Reservoirs, Dams, and Waterways	278,749,571	54,536,109
30	(333) Water Wheels, Turbines, and Generators	57,361,884	3,905,020
31	(334) Accessory Electric Equipment	17,463,811	1,311,023
32	(335) Misc. Power PLant Equipment	2,100,890	-45
33	(336) Roads, Railroads, and Bridges	10,883,825	179,792
34	(337) Asset Retirement Costs for Hydraulic Production	5,128	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	423,747,272	62,133,354
36	D. Other Production Plant		
37	(340) Land and Land Rights	48,946	
38	(341) Structures and Improvements	163,194,522	4,556,118
39	(342) Fuel Holders, Products, and Accessories	124,260,556	1,248,636
40	(343) Prime Movers		
41	(344) Generators	1,924,236,478	51,521,046
42	(345) Accessory Electric Equipment	95,082,111	12,480,878
43	(346) Misc. Power Plant Equipment	14,999,960	192,569
44	(347) Asset Retirement Costs for Other Production	10,054,252	3,797,023
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,331,876,825	73,796,270
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,897,052,966	166,551,053

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 2015/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	11,521,146	
49	(352) Structures and Improvements	18,934,161	418,717
50	(353) Station Equipment	265,764,953	9,882,380
51	(354) Towers and Fixtures	48,733,211	10,666
52	(355) Poles and Fixtures	23,013,784	429,776
53	(356) Overhead Conductors and Devices	76,981,724	46,202
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	34,109	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	445,269,420	10,787,741
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	21,600,436	2,376,840
61	(361) Structures and Improvements	39,859,326	322,399
62	(362) Station Equipment	431,913,923	43,036,036
63	(363) Storage Battery Equipment	384,933	2,283
64	(364) Poles, Towers, and Fixtures	352,871,314	12,700,039
65	(365) Overhead Conductors and Devices	572,996,660	14,770,443
66	(366) Underground Conduit	15,354,540	30,661
67	(367) Underground Conductors and Devices	663,267,386	27,456,548
68	(368) Line Transformers	338,021,932	21,245,380
69	(369) Services	411,082,900	20,889,870
70	(370) Meters	140,813,509	9,014,036
71	(371) Installations on Customer Premises	376,133	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	81,632,862	2,968,195
74	(374) Asset Retirement Costs for Distribution Plant	476,732	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,070,652,586	154,812,730
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	9,663,128	157
87	(390) Structures and Improvements	108,989,466	14,872,003
88	(391) Office Furniture and Equipment	94,963,071	26,192,609
89	(392) Transportation Equipment	43,747,131	10,160,910
90	(393) Stores Equipment	2,951,002	1,656
91	(394) Tools, Shop and Garage Equipment	14,612,246	1,625,212
92	(395) Laboratory Equipment	9,817,734	169,683
93	(396) Power Operated Equipment	45,158,267	2,581,915
94	(397) Communication Equipment	95,751,299	4,509,909
95	(398) Miscellaneous Equipment	147,376	160,698
96	SUBTOTAL (Enter Total of lines 86 thru 95)	425,800,720	60,274,752
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	65,289	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	425,866,009	60,274,752
100	TOTAL (Accounts 101 and 106)	8,316,405,437	473,985,386
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)	8,316,405,437	473,985,386

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
		144,504	182,591,124		3
2,999,760			373,677,186		4
2,999,760		144,504	556,268,310		5
					6
					7
			4,161,715		8
119,421			255,816,364		9
2,755,497			585,545,827		10
					11
227,005			189,044,231		12
4,373			55,266,118		13
3,333			14,836,071		14
			64,270,343		15
3,109,629			1,168,940,669		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			6,047,627		27
84,725			53,251,266		28
28,589		-131,967	333,125,124		29
595,029			60,671,875		30
107,580			18,667,254		31
2,270			2,098,575		32
3,154			11,060,463		33
			5,128		34
821,347		-131,967	484,927,312		35
					36
			48,946		37
5,833			167,744,807		38
1,133,819			124,375,373		39
					40
2,129,277			1,973,628,247		41
85,378			107,477,611		42
10,655			15,181,874		43
			13,851,275		44
3,364,962			2,402,308,133		45
7,295,938		-131,967	4,056,176,114		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 2015/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
		-12,538	11,508,608		48
39,961			19,312,917		49
133,308		260,801	275,774,826		50
			48,743,877		51
		2,270,650	25,714,210		52
		-2,270,650	74,757,276		53
					54
					55
			286,332		56
			34,109		57
173,269		248,263	456,132,155		58
					59
25,046			23,952,230		60
380,352			39,801,373		61
3,128,511		484,231	472,305,679		62
			387,216		63
15,960,699			349,610,654		64
202,320		-212,590	587,352,193		65
			15,385,201		66
304,588		-107,263	690,312,083		67
1,176,622		-212,590	357,878,100		68
14,883,996		-1,017,448	416,071,326		69
421,215			149,406,330		70
			376,133		71
					72
2,437,521		804,858	82,968,394		73
			476,732		74
38,920,870		-260,802	3,186,283,644		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
8,689			9,654,596		86
4,398,489			119,462,980		87
10,792,713		-38	110,362,929		88
1,720,006			52,188,035		89
122,017			2,830,641		90
826,231			15,411,227		91
741,470			9,245,947		92
2,843,038			44,897,144		93
1,612,363			98,648,845		94
		38	308,112		95
23,065,016			463,010,456		96
					97
			65,289		98
23,065,016			463,075,745		99
72,454,853		-2	8,717,935,968		100
					101
					102
					103
72,454,853		-2	8,717,935,968		104

Schedule Page: 204 Line No.: 104 Column: e

In 1985, PGE sold a 15% undivided interest in the Boardman plant and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under the terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. This transaction was approved by the FERC on December 19, 2013 through Docket EC14-13-000.

The original cost of the 15% of the Boardman Plant and the 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line at December 31, 2013 is estimated at $96 million and $2 million, respectively. It was also estimated that these assets were fully depreciated at the time the acquisition was executed since it coincided with the expiration of various agreements under the terms of the original 1985 transaction.

The proposed final accounting entries associated with this transaction were submitted to the FERC on June 27, 2014, in compliance with the accounting under the Uniform System of Accounts (Docket AC14-129-000). On September 29, 2014, the FERC approved the final proposed journal entries. In September 2014, the final accounting entries were executed which increased both FERC Account 101, Electric plant in service, and FERC Account 108, Accumulated provision for depreciation by $97,861,972 (Steam $94,061,144, and Transmission $3,800,827) with corresponding offsets to Account 102, Electric plant purchased or sold.

In December 2014 PGE acquired a 10% undivided interest from Power Resources Cooperative (Power Resources) in the Boardman Plant, and associated equipment and facilities (Boardman Project), as well as certain contracts and other rights related to Power Resources ownership interest in the Boardman Project. The jurisdictional facilities associated with the Proposed Transaction consist of an undivided interest in the generator tie lines and other interconnection facilities of the Boardman Project, the Turlock Irrigation District purchase power agreement, and associated books and records.

The original cost of the 10% of the Boardman Plant and Generator Tie Lines at December 31, 2014 was estimated at $65,882,727 and $1,328,594 respectively.

On September 19, 2014 PGE filed an application requesting authorization for the acquisition of the rights, titles, and interests associated with this transaction pursuant to section 203(a)(1) of the Federal Power Act including proposed accounting entries. The FERC concluded that the proposed transaction was consistent with public interest and authorized the transaction on November 14, 2014 (Docket EC14-147-000). In December 2014, accounting entries were executed, which increased FERC Account 101, Electric plant in service (Steam Plant $65,882,727 and Transmission $1,328,594) FERC Account 108, Accumulated provision for depreciation by $47,707,066 (Steam $46,764,020 and Transmission $943,046), and FERC 107, Construction work in progress by $372,000 with corresponding offsets to Account 114, Electric plant acquisition adjustments.

On April 20, 2015 (Docket EC14-147-000) PGE submitted proposed final journal entries for acceptance as prescribed under Electric Plant Instruction No. 5 and Account 102, Electric plant purchased or sold. Based on discussion with FERC Commission staff, PGE re-filed on May 27, 2015 (Docket AC15-110-000) clearing the negative acquisition recorded to Account 114, Electric plant acquisition adjustment immediately instead of amortizing the balance over the remaining life of the plant. On July 6, 2015 (Docket EC14-147-000) the FERC approved the proposed journal entries.

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 2015/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
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					
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 2015/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	Future	2,817,508
4	Sewell Easement, Washington County, OR	2009	Future	334,928
5	North Bethany, Washington County, OR	2014	2018	538,078
6				
7	Other Land and Land Rights (8 in Number)	Various	Various	404,526
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
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				
47	Total			4,638,631

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 2015/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	Construct Carty Generating Plant	423,901,576
2	Customer Engagement Transformation - Billing/Meter Data Management System - Software	14,951,881
3	Blue Lake/Gresham - System Upgrades	10,549,750
4	Construct Marquam Project	8,670,765
5	West Union - 115kV Conversion	7,328,394
6	Horizon Substation Phase II Project	7,301,696
7	Energy Trading and Risk Management Consolidation - Software	5,554,724
8	Westside Hydro Structural/Reliability Upgrades	5,481,221
9	Field Data Communication System	5,170,231
10	Oak Grove - Build Harriet Power House	5,137,796
11	Marquam Tri-Met Bridge 115kV Line	4,614,438
12	Colstrip Coal Capital Project	4,419,575
13	Clackamas River Hydro Project	3,477,751
14	Web Fitness- Remove Self Service Barriers - Software	3,373,549
15	Beaver Plant - Replace Heat Recovery Steam Generator/Superheaters	3,023,026
16	Network Access Management	2,564,498
17	Clackamas Protection Mitigation Enhancement - Habitat Improvement	2,554,852
18	Pelton Round Butte Project Protection Mitigation Enhancement Fund	2,282,973
19	Power Supply Engineering Services - Generation Plant Fitness Project	1,926,158
20	Harborton Natural Resource Mitigation	1,687,039
21	River District Infrastructure - Install Vaults and Conduits	1,430,117
22	Pelton Round Butte Mitigation Fund - Programmatic Activities in Deschutes River Basin-Wate	1,414,199
23	Distribution System Construction II	1,279,825
24	Abernethy Substation Capacity Addition	1,262,348
25	Substation Arc Flash Safety Improvements	1,071,707
26		
27	Minor Projects <$1,000,000, Represents 3% of total of CWIP balance	14,615,253
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	545,045,342

Schedule Page: 216   Line No.: 12   Column: a

Jointly owned with Northwestern Energy, LLC, Talen Montana, LLC, Puget Sound Energy, Inc., Pacific Corp, and Avista Corporation. Respondent's 20% share of jointly owned cost is reported.

Schedule Page: 216   Line No.: 18   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.: 22   Column: a

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.

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 2015/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	3,656,289,552	3,656,289,552		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	252,397,595	252,397,595		
4	(403.1) Depreciation Expense for Asset Retirement Costs	5,026,773	5,026,773		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,637,202	3,637,202		
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)	261,322,922	261,322,922		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	69,421,358	69,421,358		
13	Cost of Removal	8,389,942	8,389,942		
14	Salvage (Credit)	7,706,525	7,706,525		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	70,104,775	70,104,775		
16	Other Debit or Cr. Items (Describe, details in footnote):	20,363,636	20,363,636		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,867,871,335	3,867,871,335		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	867,704,935	867,704,935		
21	Nuclear Production				
22	Hydraulic Production-Conventional	181,579,748	181,579,748		
23	Hydraulic Production-Pumped Storage				
24	Other Production	574,387,175	574,387,175		
25	Transmission	209,277,373	209,277,373		
26	Distribution	1,849,206,854	1,849,206,854		
27	Regional Transmission and Market Operation				
28	General	185,715,250	185,715,250		
29	TOTAL (Enter Total of lines 20 thru 28)	3,867,871,335	3,867,871,335		

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

In 1985, PGE sold a 15% undivided interest in the Boardman plant and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under the terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. This transaction was approved by the FERC on December 19, 2013 through Docket EC14-13-000.

The original cost of the 15% of the Boardman Plant and the 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line at December 31, 2013 is estimated at $96 million and $2 million, respectively. It was also estimated that these assets were fully depreciated at the time the acquisition was executed since it coincided with the expiration of various agreements under the terms of the original 1985 transaction.

The proposed final accounting entries associated with this transaction were submitted to the FERC on June 27, 2014, in compliance with the accounting under the Uniform System of Accounts (Docket AC14-129-000). On September 29, 2014, the FERC approved the final proposed journal entries. In September 2014, the final accounting entries were executed which increased both FERC Account 101, Electric plant in service, and FERC Account 108, Accumulated provision for depreciation by $97,861,972 (Steam $94,061,144, and Transmission $3,800,827) with corresponding offsets to Account 102, Electric plant purchased or sold.

In December 2014 PGE acquired a 10% undivided interest from Power Resources Cooperative (Power Resources) in the Boardman Plant, and associated equipment and facilities (Boardman Project), as well as certain contracts and other rights related to Power Resources ownership interest in the Boardman Project. The jurisdictional facilities associated with the Proposed Transaction consist of an undivided interest in the generator tie lines and other interconnection facilities of the Boardman Project, the Turlock Irrigation District purchase power agreement, and associated books and records.

The original cost of the 10% of the Boardman Plant and Generator Tie Lines at December 31, 2014 was estimated at $65,882,727 and $1,328,594 respectively.

On September 19, 2014 PGE filed an application requesting authorization for the acquisition of the rights, titles, and interests associated with this transaction pursuant to section 203(a)(1) of the Federal Power Act including proposed accounting entries. The FERC concluded that the proposed transaction was consistent with public interest and authorized the transaction on November 14, 2014, (Docket EC14-147-000). In December 2014, accounting entries were executed, which increased FERC Account 101, Electric plant in service (Steam Plant $65,882,727 and Transmission $1,328,594) FERC Account 108, Accumulated provision for depreciation by $47,707,066 (Steam $46,764,020 and Transmission $943,046), and FERC 107, Construction work in progress by $372,000 with corresponding offsets to Account 114, Electric plant acquisition adjustments.

On April 20, 2015 (Docket EC14-147-000) PGE submitted proposed final journal entries for acceptance as prescribed under Electric Plant Instruction No. 5 and Account 102, Electric plant purchased or sold. Based on discussion with FERC Commission staff, PGE re-filed on May 27, 2015 (Docket AC15-110-000) clearing the negative acquisition recorded to Account 114, Electric plant acquisition adjustment immediately instead of amortizing the balance over the remaining life of the plant. On July 6, 2015 (Docket EC14-147-000) the FERC approved the proposed journal entries.

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 2015/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			176,125
4	Sub - TOTAL			177,125
5				
6	Salmon Springs Hospitality Group			
7	Common Stock	04/09/98		10,000
8	Equity in Earnings			8,959
9	Sub - TOTAL			18,959
10				
11	SunWay 2, LLC			
12	Paid in Capital	9/16/08		1,276,014
13	Dissolution			
14	Equity in Earnings			-641
15	Sub - TOTAL			1,275,373
16				
17	SunWay 3, LLC			
18	Paid in Capital	10/19/09		2,415,395
19	Equity in Earnings			-877
20	Sub - TOTAL			2,414,518
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	3,885,975

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 2015/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
		176,125		3
		177,125		4
				5
				6
		10,000		7
239,359	-270,000	-21,682		8
239,359	-270,000	-11,682		9
				10
				11
	21,215	1,297,229		12
		-1,296,589		13
1		-640		14
1	21,215			15
				16
				17
		2,415,395		18
-7		-884		19
-7		2,414,511		20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
239,353	-248,785	2,579,954		42

Schedule Page: 224 Line No.: 15 Column: g

On January 5, 2015, PGE acquired the assets and liabilities of SunWay 2, LLC, a variable interest entity, at net book value. The entity was subsequently dissolved.

Schedule Page: 224 Line No.: 20 Column: g

Represents PGE's share of SunWay 3, LLC, a variable interest entity jointly owned by PGE (0.01% interest) and Firstar Development, LCC, 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.

SunWay 3, LLC statistics at 12/31/2015 (100%)

In-service Production cost: $7,454,015
Total installed capacity: 2.4 MW
Operations and Maintenance for 2015: $454,980

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 2015/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)	39,025,434	37,743,684	Generation
2	Fuel Stock Expenses Undistributed (Account 152)	3,333,157		Generation
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	11,206,292	9,638,431	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	20,644,198	21,101,321	Generation
8	Transmission Plant (Estimated)	237,700	266,663	Transmission
9	Distribution Plant (Estimated)	3,574,388	8,587,718	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	307,083	264,386	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	35,969,661	39,858,519	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	3,164,304	4,074,812	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	81,492,556	81,677,015	

Schedule Page: 227 Line No.: 2 Column: c

Biomass raw material used for co-fire test burn.

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 2015/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)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	32,484.00		10,031.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	5,317.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	27,167.00		10,031.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	1,153.06		144.78	
37	Add: Withheld by EPA	48.38		48.37	
38	Deduct: Returned by EPA				
39	Cost of Sales	193.15			
40	Balance-End of Year	1,008.29		193.15	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		21		
45	Gains		21		
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.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
10,030.00		10,031.00		138,853.00		201,429.00		1
								2
								3
				1,320.00		1,320.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						5,317.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
10,030.00		10,031.00		140,173.00		197,432.00		29
								30
								31
								32
								33
								34
								35
144.78		144.78		3,823.82		5,411.22		36
48.37		48.37		1,150.63		1,344.12		37
								38
				193.15		386.30		39
193.15		193.15		4,781.30		6,369.04		40
								41
								42
								43
					6		27	44
					6		27	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 2015/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)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2017		2018		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
								7
								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					

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;	313,633,872	4,780,078	407,254	4,714,495	65,583
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 No. 07-015, dtd 1/12/2007)					
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	313,633,872	4,780,078		4,714,495	65,583

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

(1) $3,500,000 - Recovery of Trojan decomissioning costs, included in retail prices, until decommissioning is complete, as authorized by OPUC (Order #07-015, dtd 1/12/2007 and updated by Order #10-478, dtd 12/17/2010), offset in Account 407.

(2) $1,214,495 - Reclass of the balance of unrecovered plant and regulatory study costs related to Trojan to Account 254, Regulatory liability. Settlement proceeds from a legal matter associated with the costs of the Independent Spent Fuel Storage Installation created a regulatory liability.

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 2015/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	PTP-45 SIS	370	561.6		456
3	PTP-46 SIS	369	561.6		456
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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 2015/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	Tax Benefits Related to Book/Tax Basis Differences	53,544,357	859,908	282	782,214	53,622,051
2	Previously Flowed to Customers	35,696,238	573,272	283	521,476	35,748,034
3	(Amort. period is based on the lives of the					
4	properties, approximately 25 years.)					
5						
6	Photovoltaic Volumetric Incentive Pilot	1,144,565	6,733,627	407.3	6,247,784	1,630,408
7	(per OPUC Order No. 10-198 dtd 5/28/2010)					
8	Reauthorized OPUC Order No.15-185 dtd 6/09/2015)					
9	(Amortization period 5/07/2015 - 5/6/2016)					
10						
11	Colstrip Common Facilities (28 year amort. ending	751,667		407.3	322,140	429,527
12	2017, FERC OCA-AD ltr dtd 5/23/1989)					
13						
14	Price Risk Management	220,696,581	153,946,972	555/547	94,635,262	280,008,291
15						
16	Deferred Broker Settlement	3,609,159		555	1,831,039	1,778,120
17						
18	Intervenor Funding (original deferral per OPUC	822,884	296,275			1,119,159
19	Order No. 03-388 dtd 7/2/2003)					
20						
21	Independent Evaluator Deferral (2011)	516,480	4,590	407.3	546,659	-25,589
22	(per OPUC Order No. 11-154 dtd 5/10/2011)					
23	(per Advice No. 14-24 dtd 11/12/2014)					
24	(Amortization period 01/01/2015-12/31/2015)					
25						
26	Generation Plant Maintenance Deferral	2,737,968		557	684,492	2,053,476
27	(per OPUC Order no. 08-601 dtd 12/29/2008;					
28	(amortization period: 1/1/2009 - 12/31/2018)					
29						
30	Residential Sch 123 SNA Deferral-2013	2,579,431	25,750	456	2,486,481	118,700
31	(reauthorized Advice No.14-20 dtd 10/30/2014)					
32	(amortization period: 6/1/2014-12/31/2015)					
33						
34	Residential Sch 123 SNA Deferral-2015		6,359,174	229	6,359,170	4
35	(authorized per OPUC Order No.15-019 dtd 1/28/2015)					
36						
37	Residual Deferred Account	(244,830)		421	6,641	-251,471
38	(per OPUC Order No. 10-279 dtd 7/23/2010)					
39						
40	Glass Insulator Deferral	2,479,564	891,338	571	45,494	3,325,408
41	(per OPUC Order No. 10-478 dtd 12/17/2010;					
42	UE 215 First Revenue Requirement Stipulation)					
43						
44	TOTAL	614,275,595	193,639,290		168,396,577	639,518,308

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 2015/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	Pension Funding	235,843,743	12,517,323	219/926	19,885,800	228,475,266
3	Postretirement Funding	10,762,885	592,985	219/926	1,069,920	10,285,950
4	(per SFAS No. 158 adopted 12/31/2006;					
5	OPUC Order No. 07-051 dtd 2/12/2007)					
6						
7	Boardman Decommissioning Balancing	433,753	131,500			565,253
8	(per Advice No. 11-07 dtd 05/27/2011)					
9						
10	UE 215 Four Capital Projects Deferral-2012 Vintage	(230,125)	207,457			-22,668
11	(per OPUC Order No. 10-478 dtd 12/17/2010,					
12	UE 215 Second Revenue Requirement Stipulation)					
13	Approved into amortization as part of UE 262					
14	(per OPUC Order No.13-459 dtd 12/09/2013)					
15	amortization period: 1/1/2014 - 12/31/2014					
16						
17	UE 215 Four Capital Projects Deferral-2013 Vintage	19,358,413	191,262	407.3	19,164,102	385,573
18	(per OPUC Order No. 10-478 dtd 12/17/2010,					
19	UE 215 Second Revenue Requirement Stipulation)					
20	Approved into amortization per OPUC docket					
21	No.UE-292, Advice No.14-13 dtd 11/12/14)					
22	amortization period: 1/1/2015 - 12/31/2015					
23						
24	Environmental Remediation Deferral	3,100,000		923	1,550,000	1,550,000
25	(Amortization per OPUC Order No.14-422,					
26	dtd 12/4/14, GRC docket UE-283)					
27	Amortization period 1/1/2015-12/31/2016					
28						
29	Automated Demand Response Cost Recovery Mechanism	117,500	1,088,106	Various	1,205,606	
30	(per OPUC order No 13-059 dtd 2/26/2013					
31	Amortization per Advice No 13-04 dtd 3/8/2013					
32						
33	2013 Lost Revenue Recovery Adjustment (LRRA)	3,869,029	218,313	456	4,048,206	39,136
34	(reauthorized OPUC Order No.13-044 dtd 2/12/2013)					
35	Amortization period 6/1/2014-12/31/2015					
36						
37	Direct Access Open Enrollment Deferral -2013	63,264	1,895	447	65,150	9
38	(per OPUC Docket UE 246					
39	Advice No.12-09 dtd 12/18/2012)					
40	Amortization period 1/1/2014-12/31/2014					
41						
42						
43						
44	TOTAL	614,275,595	193,639,290		168,396,577	639,518,308

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	IT O&M 2014 Deferral	6,947,200		Various	1,736,800	5,210,400
3	(per OPUC GRC Order No.13-459, dtd 12/9/2013					
4	S-9 Partial Stipulation)					
5	Amortization period 1/1/2014-12/31/2018					
6						
7	CET 2014 Deferral	5,897,007		903	1,605,474	4,291,533
8	(per OPUC GRC Order No.13-459, dtd 12/9/2013					
9	S-7 Partial Stipulation)					
10	Amortization period 1/1/2014-12/31/2018					
11						
12	Tucannon RAC Deferral	1,439,747	48,285	456	1,357,884	130,148
13	(per OPUC GRC UE-283 Order No.14-422, dtd 12/4/14					
14	and Advice No.14-06, dtd 3/31/2014)					
15	Amortization period 7/1/2015-12/31/2015					
16	(per Order No.15-129)					
17						
18	Port Westward Major Maintenance Accrual	2,339,115	455,884			2,794,999
19	(per OPUC GRC Order No.13-459, dtd 12/9/2013)					
20						
21	Schedule 110 Energy Efficiency		908,586	Various	908,483	103
22	(per OPUC Advice No. 10-01)					
23						
24	TID PPA Prepaid coal unearned revenue		695,200			695,200
25	(per OPUC GRC Order NO. 14-442, UE-283,					
26	and Advice No. 14-03)					
27						
28	CET 2015 Deferral		5,783,564	903	1,330,300	4,453,264
29	(Per OPUC GRC Order NO. 13-459, UE-266,					
30	and Advice NO. 13-03)					
31	(amortization per OPUC Order No. 14-422,					
32	dtd 12/04/2014, 2015 GRC Docket UE-283					
33	amortization period 01/01/2015-12/31/2018)					
34						
35	Direct Access Reg Deferral 2015		670,011			670,011
36	(Per OPUC GRC Order No. 15-023, UM 1301)					
37	Amortization period 1/1/16 - 12/31/16					
38						
39	Deferred Cost - Pricing Program (Pricing Pilot)		392,588			392,588
40	(Per OPUC Order No. 15-203 dtd 6/23/15, UM 1708)					
41						
42	Deferred Cost - DLC Thermostat Nest Pilot)		29,076			29,076
43	(Per OPUC Order No. 15-203 dtd 6/23/15, UM 1708)					
44	TOTAL	614,275,595	193,639,290		168,396,577	639,518,308

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 2015/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	PPS Solar - Revenue Requirement Deferral		16,349			16,349
3	(per OPUC Order No. 15-304 dtd 10/02/15,					
4	Docket UM 1724)					
5	Included in Renewable Resources Automatic					
6	Adjustment Clause					
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	TOTAL	614,275,595	193,639,290		168,396,577	639,518,308

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

Current year reauthorization approved through OPUC Orders:
$66,125 Order 15-001 dtd 1/7/15, Docket UM 1357(53)
$66,092 Order 15-101 dtd 4/2/15, Docket UM 1357
$ 776 Order 15-187 dtd 6/9/15, Docket UM 1690
$50,000 Order 15-240 dtd 8/13/15, Docket UE 294
$ 8,000 Order 15-252 dtd 8/26/15, Docket UM 1633
$54,552 Order 15-277 dtd 11/14/15, Docket UE 294
$ 4,000 Order 15-302 dtd 9/30/15, Docket UM 1713
$ 9,491 Order 15-312 dtd 10/8/15, Docket UM 1662
$ 8,239 Order 15-376 dtd 11/19/15, Docket UM 1662
$10,000 Order 15-378 dtd 11/19/15, Docket UM 1713
$19,000 interest accrued in 2015.

Schedule Page: 232 Line No.: 21 Column: f

After final amortization in Jan 2016, the residual credit balance will be transferred to the Residual Deferred Account, pursuant to OPUC Order No. 10-279 dated July 23,2010.

Schedule Page: 232 Line No.: 34 Column: e

Account balance reclassed to account 229.

Schedule Page: 232 Line No.: 34 Column: f

Rounding error when balance was reclassed. Will be reclassed to account 229 in 2016.

Schedule Page: 232.1 Line No.: 29 Column: d

Amounts charged to accounts 456,555,and 908.

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

Balance will be reclassed to the Residual Deferred Account in 2016.

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

Amounts charged to accounts 903,921,598,549,566.

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

Amounts charged to accounts 407.3,431 and 254.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	-199,349	346,309	various	450,731	-303,771
3						
4	Net Co-owner / Trust Contributi	117,003	115,126,573	various	115,105,789	137,787
5						
6	Deferred Rent - WTC Tenant					
7	amort. through 2021	826,775		418	99,819	726,956
8						
9	Deferred Revolving Credit					
10	Agreement Fees					
11	amort. through 2020	1,710,205	414,709	431	1,024,173	1,100,741
12						
13	Dispatchable Generation					
14	various amort. periods from					
15	2005 and extending through 2025	9,142,412	2,934,224	903	1,130,778	10,945,858
16						
17	LID Receivable from WTC Tenants					
18	amort. over 20 yrs through 2029	89,839		418	5,990	83,849
19						
20	Utility Property Sales-					
21	Selling Expenses	17,767	963,848	254	950,038	31,577
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						
47	Misc. Work in Progress	72,155				-134,545
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	11,776,807				12,588,452

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	-10,738,741	-27,706,907
3	Regulatory Liabilities	47,454,122	41,636,022
4	Employee Benefits	160,994,463	170,572,407
5	Price Risk Management	91,209,388	116,155,437
6	Tax Credits & NOL's	13,236,327	45,658,519
7	Other	17,462,242	18,577,027
8	TOTAL Electric (Enter Total of lines 2 thru 7)	319,617,801	364,892,505
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	4,525,075	4,735,392
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	324,142,876	369,627,897

Notes

Line 7 - Other

	Ending Bal 12/31/2014	Ending Bal 12/31/2015
Bad Debt Expense	$2,563,595	$2,456,610
Nuclear Decommissioning Trust	3,977,456	5,384,206
Renewable Energy Development	6,068,920	5,779,465
Miscellaneous	4,852,271	4,956,746
Total Line 7 - Other	$17,462,242	$18,577,027

Line 17 - Other Non Utility	Ending Bal 12/31/2014	Ending Bal 12/31/2015
Property Related	$4,245,847	$4,471,690
Employee Benefits	279,228	263,702
Total Line 17 - Other Non Utility	$4,525,075	$4,735,392

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 2015/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 Cumlative Preferred	30,000,000		
8				
9	Total_Pre	30,000,000		
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				

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 2015/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
88,792,751	1,199,786,255					2
						3
88,792,751	1,199,786,255					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

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 2015/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	4,804,482
3	compensation and associated income tax benefits	
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	3,574,896
18	Reacquired common stock	-68,327
19	Former parent assumption of PGE tax liabilities of Non-Qualified Pn	610,028
20	Oregon tax credit related to PGE's separation from former parent	8,317,516
21	SUBTOTAL ACCOUNT 211	12,428,645
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	18,838,745

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

Represents the assumption of PGE's 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	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2015/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	23,073,915
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	23,073,915

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 2015/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	9.31% Medium-Term Note Series Due 8/11/2021	20,000,000	176,577
4	6.75% Series VI Due 8/1/2023	50,000,000	519,234
5			437,500 D
6	6.875% Series VI Due 8/1/2033	50,000,000	519,257
7			437,500 D
8	6.26% Series Due 5/1/2031	100,000,000	723,856
9	6.31% Series Due 5/1/2036	175,000,000	1,270,565
10	5.80% Series Due 6/1/2039	170,000,000	1,460,968
11	5.81% Series Due 10/1/2037	130,000,000	1,109,574
12			517,518 D
13	5.80% Series Due 03/01/2018	75,000,000	282,501
14			
15	6.80% Series Due 1/15/2016 - Order No. 08-106 01/28/2008	67,000,000	456,731
16	6.10% Series Due 4/15/2019 - Order No. 09-089 03/16/2009	300,000,000	2,386,224
17			222,000 D
18	5.43% Series Due 5/3/2040 - Order No. 09-245 06/22/2009	150,000,000	1,034,284
19	3.46% Series Due 1/14/2015 - Order No. 09-405 10/08/2009	70,000,000	455,869
20	3.81% Series Due 6/15/2017 - Order No. 09-405 10/08/2009	58,000,000	375,096
21	4.47% Series Due 6/15/2044 - Order No. 13-098 03/26/2013	150,000,000	1,113,047
22	4.47% Series Due 8/14/2043 - Order No. 13-098 03/26/2013	75,000,000	558,740
23	4.84% Series Due 12/15/2048 - Order No. 13-098 03/26/2013	50,000,000	652,029
24	4.74% Series Due 11/15/2042 - Order No. 13-098 03/26/2013	105,000,000	311,154
25			
26	4.39% Series Due 8/15/2045 - Order No. 14-145 04/29/2014	100,000,000	645,383
27	4.44% Series Due 10/15/2046 - Order No. 14-145 04/29/2014	100,000,000	625,030
28	3.51% Series Due 11/15/2024 - Order No. 14-145 04/29/2014	80,000,000	501,502
29			
30	3.55% Series Due 1/15/2030 - Order No. 14-399 11/12/2014	75,000,000	325,296
31	3.50% Series Due 5/15/2035 - Order No. 14-399 11/12/2014	70,000,000	305,128
32			
33	TOTAL	2,646,489,838	20,687,174

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 2015/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	Pollution Control Bonds (Guaranteed by Company) -		
2	Port of Morrow, OR Series 1998A 5% Due 5/1/2033	23,600,000	604,452
3	City of Forsyth, MT Series 1998A 5% Due 5/1/2033	97,800,000	2,615,167
4			
5	SUBTOTAL ACCOUNT 221	2,341,400,000	20,642,182
6			
7	ACCOUNT 224 - OTHER LONG TERM DEBT		
8	Variable Interest Due - Libor + 70 basis pts Due 10/30/2015 - Order 14-145 04/29/14	75,000,000	11,248
9	Variable Interest Due - Libor + 70 basis pts Due 10/30/2015 - Order 14-145 04/29/14	75,000,000	11,248
10	Variable Interest Due - Libor + 70 basis pts Due 10/30/2015 - Order 14-145 04/29/14	75,000,000	11,248
11	Variable Interest Due - Libor + 70 basis pts Due 10/30/2015 - Order 14-145 04/29/14	80,000,000	11,248
12	City of Portland Improvement District Loan	89,838	
13	SUBTOTAL ACCOUNT 224	305,089,838	44,992
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	2,646,489,838	20,687,174

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
08/12/1991	08/11/2021	08/12/1991	08/11/2021	20,000,000	1,862,000	3
08/01/2003	08/01/2023	08/01/2003	08/01/2023	50,000,000	3,375,000	4
						5
08/01/2003	08/01/2033	08/01/2003	08/01/2033	50,000,000	3,437,500	6
						7
05/26/2006	05/01/2031	05/26/2006	05/01/2031	100,000,000	6,260,000	8
05/26/2006	05/01/2036	05/26/2006	05/01/2036	175,000,000	11,042,500	9
05/16/2007	06/01/2039	05/16/2007	06/01/2039	170,000,000	9,860,000	10
09/19/2007	10/01/2037	09/19/2007	10/01/2037	130,000,000	7,553,000	11
						12
12/12/2007	03/01/2018	12/12/2007	03/01/2018	75,000,000	4,350,000	13
						14
01/15/2009	01/15/2016	01/15/2009	01/15/2016		1,771,778	15
04/16/2009	04/15/2019	04/16/2009	04/15/2019	300,000,000	18,300,000	16
						17
11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	8,145,000	18
01/15/2010	01/14/2015	01/15/2010	01/14/2015		98,310	19
06/15/2010	06/15/2017	06/15/2010	06/15/2017	58,000,000	2,209,800	20
6/27/2013	6/15/2044	6/27/2013	6/15/2044	150,000,000	6,705,000	21
8/29/2013	8/14/2043	8/29/2013	8/14/2043	75,000,000	3,352,500	22
12/16/2013	12/15/2048	12/16/2013	12/15/2048	50,000,000	2,420,000	23
11/15/2013	11/15/2042	11/15/2013	11/15/2042	105,000,000	4,977,000	24
						25
8/15/2014	8/15/2045	8/15/2014	8/15/2045	100,000,000	4,390,000	26
10/15/2014	10/15/2046	10/15/2014	10/15/2046	100,000,000	4,440,000	27
11/17/2014	11/15/2024	11/17/2014	11/15/2024	80,000,000	2,808,000	28
						29
1/15/2015	1/15/2030	1/15/2015	1/15/2030	75,000,000	2,558,958	30
5/15/2015	5/15/2035	5/15/2015	5/15/2035	70,000,000	1,510,833	31
						32
				2,204,483,849	118,606,342	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
05/28/1998	05/01/2033	05/28/1998	05/01/2033	23,600,000	1,180,000	2
05/28/1998	05/01/2033	05/28/1998	05/01/2033	97,800,000	4,890,000	3
						4
				2,204,400,000	117,497,179	5
						6
						7
5/12/2014	10/30/2015	05/12/2014	10/30/2015		287,659	8
05/31/2014	10/30/2015	05/31/2014	10/30/2015		311,398	9
06/30/2014	10/30/2015	06/30/2014	10/30/2015		163,614	10
07/21/2014	10/30/2015	07/21/2014	10/30/2015		346,492	11
11/16/2009	11/16/2029			83,849		12
				83,849	1,109,163	13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				2,204,483,849	118,606,342	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	172,147,958
2		
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion & Amortization	33,558,872
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Price Risk Management and Mark-to-Market	59,311,710
11	Regulatory Credits	-18,736,429
12	Other (See Footnote)	70,784,005
13		
14	Income Recorded on Books Not Included in Return	
15	Depreciation, Depletion & Amortization	-33,773,372
16	Regulatory Debits	-25,288,745
17	Other (See Footnote)	-180,277
18		
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	-217,723,810
21	State & Local Tax Deduction	-314,526
22	Other (See Footnote)	-5,677,484
23		
24		
25		
26		
27	Federal Tax Net Income	34,107,902
28	Show Computation of Tax:	
29	Normal Federal Current Provision @ 35%	11,937,766
30	Federal Energy Credit	-9,049,542
31	RTA Adjustment	83,784
32	APIC Tax Adjustment	804,518
33	Other Miscellaneous Tax Adjustment	
34	Total Federal Income Tax	3,776,526
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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

Qualified Nuclear Decommissioning Trust	$ 3,516,876
Meals & Entertainment	868,357
Political Activity	866,200
Bad Debts	(267,464)
Fines and Penalties	360,566
Employee Benefits	21,107,582
Federal Tax Expense	29,852,606
Orion Contingent Royalty Payments	408,659
Obsolete Inventory	(660,040)
Unamortized Loss on Reacquited Debt	(1,146,675)
State Tax Expense	14,637,609
Miscellaneous	1,239,729
Total Other	$70,784,005

Schedule Page: 261 Line No.: 17 Column: a

Key Man Insurance Proceeds	$ 77,598
Miscelleneous	(257,875)
Total Other	$ (180,277)

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

Dividend Received Deduction	$ (52,000)
Environmental Remediation	(1,574,753)
Renewable Energy Initiatives	(748,884)
Property Tax	(3,255,125)
Miscellaneous	(46,722)
Total Other	$(5,677,484)

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 2015/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		524,688	598,737	
3	Income Tax		1,829,328	2,972,007	2,250,000	152,853
4	Foreign Insurance Excise Tax					
5	FICA (Employer Share)	1,826,535		19,474,022	19,231,271	
6	Unemployment	-2,568		124,468	119,078	
7	Power License	555,683	-237,978	2,074,879	1,966,674	
8	Superfund Tax					
9	SUBTOTAL Federal	2,504,651	1,591,350	25,170,064	24,165,760	152,853
10	State of Montana:					
11	Income Tax		15,753	2,129	20,000	
12	Elec. Energy Producers Tax	178,000		755,268	743,518	
13	Property Taxes	2,729,168		6,296,047	5,880,078	
14	SUBTOTAL Montana	2,907,168	15,753	7,053,444	6,643,596	
15	State of Oregon:					
16	Corp Excise Tax		389,737	72,233	100,300	35,921
17	Property Taxes		24,225,786	51,719,455	54,987,340	
18	City Taxes and Licenses	3,530,923		45,153,206	45,141,411	
19	Public Utility Comm Fees			4,816,447	4,816,447	
20	Department of Energy		681,248	1,667,103	1,971,706	
21	Department of Enviro Quality	460,004		440,120	418,221	
22	Unemployment	54,100		1,869,809	1,866,798	
23	Water Power Fee		936,052	580,519	589,564	
24	Transportation Tax	361,046		1,472,235	1,469,864	
25	Workers Comp Assessment	57,764		185,503	243,267	
26	County & City Income Tax		43,673	16,867	265,400	17,905
27	SUBTOTAL Oregon	4,463,837	26,276,496	107,993,497	111,870,318	53,826
28	State of Washington:					
29	Property Taxes	419,756		2,201,058	343,344	
30	Sales Tax					
31	SUBTOTAL Washington	419,756		2,201,058	343,344	
32	State of Wyoming:					
33	Sales Tax					
34	SUBTOTAL Wyoming					
35	State of California:					
36	Corporate franchise tax		557,359	278,245	20,000	
37	SUBTOTAL California		557,359	278,245	20,000	
38	Canada:					
39	Goods & Services Tax					
40	SUBTOTAL Canada					
41	TOTAL	10,295,412	28,440,958	142,696,308	143,043,018	206,679

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 2015/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
50,952					524,688	2
	954,468	4,811,999			-1,839,992	3
		9,984			-9,984	4
2,069,286		11,561,220			7,912,802	5
2,822		73,669			50,799	6
464,759	-437,107				2,074,879	7
						8
2,587,819	517,361	16,456,872			8,713,192	9
						10
	33,624	15,456			-13,327	11
189,750		441,288			313,980	12
3,145,137		5,401,265			894,782	13
3,334,887	33,624	5,858,009			1,195,435	14
						15
	381,883	465,924			-393,691	16
	27,493,671	47,797,481			3,921,974	17
3,542,718		43,406,579			1,746,627	18
					4,816,447	19
	985,851	1,667,103				20
481,903					440,120	21
57,111		1,106,693			763,116	22
	945,097				580,519	23
363,417		871,379			600,856	24
		106,141			79,362	25
	274,301	49,830			-32,963	26
4,445,149	30,080,803	95,471,130			12,522,367	27
						28
2,277,470		2,201,144			-86	29
						30
2,277,470		2,201,144			-86	31
						32
						33
						34
						35
	299,114	278,245				36
	299,114	278,245				37
						38
						39
						40
12,645,325	30,930,902	120,265,400			22,430,908	41

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

Tax payment from subsidiary.

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 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 2015/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							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

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	Accelerated cost recovery system	751,000	101	751,000		
2	tax benefit sale - amort. over					
3	service lives of related					
4	property					
5						
6	Tenant sub-lease security deposits	41,337			52,827	94,164
7						
8	Deferred Liability for Transferred	698,070	421	38,816		659,254
9	Non-Qualified Plan Benefits					
10						
11	Deferral of Environmental Remedia	1,550,000	232	1,550,000		
12						
13	TID PPA prepaid coal stock	2,134,000			748,461	2,882,461
14						
15	Deferral of Precedent Transmission		232	3,468,507	11,280,000	7,811,493
16	Service Agreement with DET, EDF					
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						
47	TOTAL	5,174,407		5,808,323	12,081,288	11,447,372

Schedule Page: 269 Line No.: 11 Column: d

Reclass current portion of accrual for Downtown Reach Clean-up to account 232.

Schedule Page: 269 Line No.: 15 Column: d

Reclass current portion of accrual for Precedent Transmission Service Agreement of DET and EDF to account 232.

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

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

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

NOTES

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

3. Use footnotes as required.

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

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	650,919,959	158,913,253	86,993,826
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	650,919,959	158,913,253	86,993,826
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	650,919,959	158,913,253	86,993,826
10	Classification of TOTAL			
11	Federal Income Tax	531,543,799	127,721,635	70,264,245
12	State Income Tax	110,506,636	28,859,644	15,476,206
13	Local Income Tax	8,869,524	2,331,974	1,253,375

NOTES

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	23,795,543	254	23,873,237	722,917,080	2
							3
							4
			23,795,543		23,873,237	722,917,080	5
							6
							7
							8
			23,795,543		23,873,237	722,917,080	9
							10
			19,750,290		19,782,402	589,033,301	11
			3,733,148		3,778,664	123,935,590	12
			312,105		312,171	9,948,189	13

NOTES (Continued)

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 2015/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	35,696,263		
4	Price Risk Management	2,930,755	1,433,859	212,493
5	Regulatory Assets	209,300,845	36,759,069	26,537,030
6	Regulatory Liabilities			
7	Other	15,452,713	2,885,608	323,135
8				
9	TOTAL Electric (Total of lines 3 thru 8)	263,380,576	41,078,536	27,072,658
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	1,840,803		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	265,221,379	41,078,536	27,072,658
20	Classification of TOTAL			
21	Federal Income Tax	214,217,529	33,178,818	21,866,378
22	State Income Tax	47,182,563	7,307,874	4,816,227
23	Local Income Tax	3,821,287	591,844	390,053

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	15,857,810	182.3	15,909,607	35,748,060	3
						4,152,121	4
						219,522,884	5
							6
						18,015,186	7
							8
			15,857,810		15,909,607	277,438,251	9
							10
							11
							12
							13
							14
							15
							16
							17
326,619	524,451					1,642,971	18
326,619	524,451		15,857,810		15,909,607	279,081,222	19
							20
263,762	423,424		13,147,942		13,189,777	225,412,142	21
58,151	93,471		2,508,939		2,518,153	49,648,104	22
4,706	7,556		200,929		201,677	4,020,976	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	$ 48,599,462	$ 64,295,252
Price Risk Mgmt Deferral	39,679,171	47,708,064
ASC 715 Pension & Post Retirement	98,642,651	95,504,486
Regulatory Deferral Earn Test Offset	6,427,842	(1,279,955)
Miscellaneous	15,951,719	13,295,037
Total Other	$209,300,845	$219,522,884

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

	Balance at Beginning of Year	Balance at End of Year
Unamortized Loss on Reacquired Debt	$ 6,077,773	$ 6,536,443
Prepaid Property Tax	9,435,123	10,721,896
Other	(60,183)	756,847
Total Other	$ 15,452,713	$ 18,015,186

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

	Balance at Beginning of Year	Balance at End of Year
Trust-Owned Life Insurance Gain/Loss	$ 671,747	$ 393,257
Reg Deferral Earn Test Offset	1,223,473	1,425,117
Other	(54,417)	(175,403)
Total Other	$1,840,803	$1,642,971

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 2015/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	Excess Deferred Taxes	3,271,912	190	235,782		3,036,130
2						
3	Gain on Asset Sales	7,865,402	407.4	7,067,150	1,352,680	2,150,932
4	(per OPUC Order No. 01-777 dtd 8/31/2001)					
5	(amortization per OPUC Advice No.14-24,					
6	dtd 11/12/2014.)					
7	(Amortization period 01/01/2015-12/31/2015)					
8						
9	Gain on Tradeable Renewable Energy Credits	1,952,227			38,013	1,990,240
10	(per OPUC Order No. 07-083 dtd 3/5/2007)					
11						
12	Boardman Severance	2,286,521			3,291,636	5,578,157
13	Advice No.14-18, dtd 11/3/2014					
14						
15	Asset Retirement Obligations:	38,592,238	407.3	1,301,458	7,786,566	45,077,346
16	Balancing Account					
17						
18	Coyote Springs Major Maintenance Deferral	3,647,916	456	317,787	411,481	3,741,610
19	(per OPUC Order No. 01-777 dtd 8/31/2001;					
20	reauthorization OPUC Order No. 10-478					
21	dtd 12/17/2010)					
22						
23	ISFSI Pollution Control Tax Credit Deferral	7,668,594	407.4	6,336,419	97,562	1,429,737
24	(per OPUC Order No. 05-136 dtd 3/15/2005)					
25	(amortization per OPUC Order No.14-422,					
26	dtd 12/04/2014, 2015 GRC Docket UE-283					
27	Amortization period 01/01/2015-12/31/2015)					
28						
29	Zero Interest Program Loan Repayments	1,842,273			284,254	2,126,527
30	(per Advice No. 05-19 dtd 12/20/2005)					
31						
32	Schedule 110 Energy Efficiency - Balancing Accout	300,118			70,972	371,090
33	(per Advice No. 07-25 dtd 5/20/2008)					
34						
35	Sunway 3 Investment Deferral	704,830	407.4	45,480		659,350
36	(per UM 1480 dtd 4/01/2010;					
37	(Amortization over 20 years commencing 2010)					
38						
39						
40						
41	TOTAL	127,549,631		38,490,993	17,890,697	106,949,335

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	Direct Access Open Enrollment - 2014	532,815	447	563,947	7,681	-23,451
2	(per Advice 13-25 dtd 11/15/2013)					
3	(amortization per OPUC Advice No.14-24,					
4	dtd 11/12/2014)					
5	(Amortization period 01/01/2015-12/31/2015)					
6						
7	Trojan Decommissioning Deferral	48,984,785	407	18,585,562	1,085,209	31,484,432
8	(amortization per OPUC Order No.14-422,					
9	dtd 12/04/2014, 2015 GRC Docket UE-283)					
10	(Amortization period 01/01/2015-12/31/2017)					
11						
12	PRC Acquisition	10,138,000	407.4	4,037,408	35,219	6,135,811
13	(per OPUC UE-283 Final GRC Order No.14-422,					
14	dtd 12/04/2014, Second Partial					
15	Stipulation dtd 09/02/2014)					
16	(amortization per OPUC Advice No.14-24,					
17	dtd 11/12/2014)					
18	(Amortization period 01/01/2015-12/31/2016)					
19						
20	Port Westward 2 LTSA				229,707	229,707
21	(per OPUC 2015 GRC Docket UE-283,					
22	OPUC Order No.14-422, dtd 12/04/2014)					
23						
24	BPA Subscription Power - Balancing Account	(238,000)			238,000	
25	(per OPUC Order No. 08-175 dtd 3/20/2008)					
26						
27	PPS Solar - Deferral of Gain on Sale/Leaseback				2,961,717	2,961,717
28	Property sale/leaseback (approved per OPUC Order					
29	No. 15-237, Docket UP 324 dtd 08/11/15)					
30	Gain deferral and amortization (per OPUC					
31	Order No. 15-304 dtd 10/02/15, Docket UM-1724)					
32	Project approved for inclusion in RRAAC (Sch 122)					
33	(per OPUC Order No. 15-304, Docket UE 297)					
34	(Amortization period 01/01/2016 -12/31/16)					
35						
36						
37						
38						
39						
40						
41	TOTAL	127,549,631		38,490,993	17,890,697	106,949,335

Schedule Page: 278 Line No.: 3 Column: e

Total net credit change in account consists of the following:

Gains & Other

$ 298,710 Gain Alder House SE Yamhill properties sale (Q1)
$ 318,437 Gain Alder House SE Yamhill properties sale (Q2)
$ 264,761 Gain Bull Run land conveyed to Western Rivers Conservancy
$ 473,549 Gain Sale of lighting poles and associated circuit feet to City of Portland
$ (89,724) Final net costs as part of Hawthorne Building sale and remediation
$ (9,059) Trailing charges for various projects

Interest - $96,007

Schedule Page: 278 Line No.: 12 Column: e

Includes $1,024,800 reclass from PRC Acquisition for PRC share of retention.

Schedule Page: 278 Line No.: 23 Column: d

Includes $5,289,784 amortization and payments per below to co-owners for their share of the Trojan Spent Fuel settlement.

$ 966,125 to Eugene Water and Electric Board
$ 80,510 to Pacificorp

Schedule Page: 278.1 Line No.: 12 Column: d

Amount consists of the following:

$ 1,884,864 Amortization of Net Economic Value Payment(2015 portion)
$ 1,151,862 Amortization of PPA Settlement(Bookout)
$ 1,024,800 Reclass to Boardman Severance account
$ (24,118) Deferral of Net Economic Value Payment (2016 portion)

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 2015/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	845,906,182	848,594,155
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	646,306,478	633,949,689
5	Large (or Ind.) (See Instr. 4)	227,985,121	221,298,764
6	(444) Public Street and Highway Lighting	15,385,088	17,151,203
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,735,582,869	1,720,993,811
11	(447) Sales for Resale	109,756,221	130,021,814
12	TOTAL Sales of Electricity	1,845,339,090	1,851,015,625
13	(Less) (449.1) Provision for Rate Refunds	-1,197,209	3,398,715
14	TOTAL Revenues Net of Prov. for Refunds	1,846,536,299	1,847,616,910
15	Other Operating Revenues		
16	(450) Forfeited Discounts	3,019,106	3,092,995
17	(451) Miscellaneous Service Revenues	1,796,073	1,716,285
18	(453) Sales of Water and Water Power	-22,164	-27,627
19	(454) Rent from Electric Property	7,608,190	7,483,167
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	47,726,337	58,669,708
22	(456.1) Revenues from Transmission of Electricity of Others	8,257,229	8,027,230
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	68,384,771	78,961,758
27	TOTAL Electric Operating Revenues	1,914,921,070	1,926,578,668

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 2015/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
7,325,314	7,461,863	742,467	735,502	2
				3
6,918,745	6,833,605	105,582	105,020	4
3,369,215	3,210,619	255	260	5
83,112	97,100	220	211	6
				7
				8
				9
17,696,386	17,603,187	848,524	840,993	10
3,162,844	3,476,895	40	40	11
20,859,230	21,080,082	848,564	841,033	12
				13
20,859,230	21,080,082	848,564	841,033	14

Line 12, column (b) includes $ -1,057,000 of unbilled revenues.

Line 12, column (d) includes -19,004 MWH relating to unbilled revenues

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

Includes $12,276,010 in revenue related to the delivery of 508,747 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 2015, 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(d).

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

Includes $15,353,434 in revenue related to the delivery of 563,403 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 2014, 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 $16,330,087 in revenue related to the delivery of 1,176,959 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2015, 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(d).

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

Includes $18,178,625 in revenue related to the delivery of 1,099,271 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2014, 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 Check Charges
Reconnect Charges
Field Service Charges
Meter Tamper Charges
Meter Test Charges
Meter Verification Charges
Revenue for E-Manager & Energy Experts

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 Check Charges
Reconnect Charges
Field Service Charges
Meter Tamper Charges

Meter Test Charges
Meter Verification Charges
Revenue for E-Manager & Energy Experts

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

Other Electric Revenues consist of the following:

	2015
RPA Balancing	54,425,291
Transmission Resale	6,636,684
Steam Sale	2,555,480
Energy Trust Contract	2,162,090
Automated Demand Response Deferred Costs	793,393
Park Revenues	510,531
Gas Resale	(1,172,918)
Tucannon RAC Deferral	(1,355,707)
Boardman Severance	(2,266,836)
Lost Rev Recovery Adj	(3,869,603)
Sch7 Sales Norm Adj	(11,342,675)
Other	650,607
Totals	$ 47,726,337

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

Other Electric Revenues consist of the following:

	2014
BPA Subscription Power - Balancing Account	49,803,095
BPA ER Wind Curtail Settled - RECS	349,841
Coyote Springs Major Maintenance	(1,232,803)
Tucannon RAC Deferral	1,437,457
Residential Sch 123 SNA Deferral	(2,953,685)
Sch 123 LRRA Deferral	894,039
Boardman Decommissioning Balancing Account	(614,251)
EE Program Delivery Contractor Services	2,187,169
PGE Share of Boardman Ash Sales	171,892
Large Generator Interconnection Process	(5,793)
Automated Demand Response Deferred Costs	(3,205,145)
Park Revenues	602,419
Steam Sales	2,494,638
Gas for Resale	(2,577,025)
Oil for Resale	807,873
Wheeling Resale	9,228,472
Other - net	1,281,512
Totals	$ 58,669,708

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 2015/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 2015/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	7,308,842	842,550,702	742,467	9,844	0.1153
3	15 Outdoor Area Lighting	3,366	1,097,480			0.3260
4	Residential Unbilled Revenue	13,106	2,258,000			0.1723
5	TOTAL Account 440	7,325,314	845,906,182	742,467	9,866	0.1155
6	General Comm. and Ind. Sales:					
7	15 Comm. Outdoor Lighting	13,422	2,708,686			0.2018
8	32 Small Nonresidential	1,589,688	171,758,493	89,286	17,804	0.1080
9	38 Optional Time of Day -	30,923	4,169,746	376	82,242	0.1348
10	Large Nonresidential					
11	47 Irrigation - Drainage - Small	22,498	3,756,644	2,007	11,210	0.1670
12	49 Irrigation - Drainage - Large	69,660	8,303,702	1,062	65,593	0.1192
13	83-S Large Nonresidential	2,833,416	254,780,435	11,260	251,636	0.0899
14	85-S Large Nonresidential	2,343,995	186,855,456	1,260	1,860,313	0.0797
15	89-S Large Nonresidential	11,180	979,099	1	11,180,000	0.0876
16	485-S COS Opt-Out - Lrg. Nonresid		7,914,536	159		
17	489-S COS Opt-Out - Lrg. Nonresid		415,239	1		
18	515-S DAS - Outdoor Area Lighting		9,122			
19	532-S DAS - Small Nonresidential		205,398	72		
20	583-S DAS - Large Nonresidential		1,054,050	59		
21	585-S DAS - Large Nonresidential		2,999,872	39		
22	Gen Comm. & Ind. Unbilled Revenue	3,963	396,000			0.0999
23	TOTAL Account 442 - Small	6,918,745	646,306,478	105,582	65,530	0.0934
24	Large Industrial Power Sales:					
25	75 Partial Requirements Service	486,715	19,974,876	1	486,715,000	0.0410
26	89-T Large Nonresidential	62,714	4,688,700	4	15,678,500	0.0748
27	85-P Large Nonresidential	702,026	52,579,513	170	4,129,565	0.0749
28	89-P Large Nonresidential	740,209	48,887,418	15	49,347,267	0.0660
29	90-P Large Nonresidential	1,412,504	86,922,497	4	353,126,000	0.0615
30	489-T COS Opt-Out - Lg. Nonreside		3,037,634	3		
31	485-P COS Opt-Out - Lrg. Nonresid		5,818,179	43		
32	489-P COS Opt-Out - Lg. Nonreside		6,600,208	9		
33	585-P DAS - Large Nonresidential		919,096	6		
34	589-P DAS - Large Nonresidential					
35	Large Industrial Unbilled Revenue	-34,953	-1,443,000			0.0413
36	TOTAL Account 442 - Large	3,369,215	227,985,121	255	13,212,608	0.0677
37	Street Lighting					
38	Various Public Street and					
39	Highway Lighting:					
40	Street Lighting	84,231	15,539,088	220	382,868	0.1845
41	TOTAL Billed	17,715,390	1,734,525,869	848,524	20,878	0.0979
42	Total Unbilled Rev.(See Instr. 6)	-19,004	1,057,000	0	0	-0.0556
43	TOTAL	17,696,386	1,735,582,869	848,524	20,855	0.0981

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 2015/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	Street Lighting Unbilled Rev	-1,119	-154,000			0.1376
2	TOTAL Account 444	83,112	15,385,088	220	377,782	0.1851
3	TOTAL Account 445					
4	Other Sales to Public Authorities					
5	Communication Devices Electr					
6	TOTAL Account 445					
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	TOTAL Billed	17,715,390	1,734,525,869	848,524	20,878	0.0979
42	Total Unbilled Rev.(See Instr. 6)	-19,004	1,057,000	0	0	-0.0556
43	TOTAL	17,696,386	1,735,582,869	848,524	20,855	0.0981

Schedule Page: 304 Line No.: 13 Column: a
Rate Schedule 83 complete title: Large Nonresidential Standard Service (31 - 200 kW).

Schedule Page: 304 Line No.: 14 Column: a
Rate schedule 85 complete title: Large Nonresidential Standard Service (201 - 4,000 kW).

Schedule Page: 304 Line No.: 15 Column: a
Rate schedule 89 complete title: Large Nonresidential (>4,000 kW) Standard Service.

Schedule Page: 304 Line No.: 16 Column: a
Rate Schedule 485 complete title: Large Nonresidential (201 - 4,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 17 Column: a
Rate Schedule 489 complete title: Large Nonresidential (>4,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 19 Column: a
Rate Schedule 532 complete title: Small Nonresidential Direct Access Service.

Schedule Page: 304 Line No.: 20 Column: a
Rate Schedule 583 complete title: Large Nonresidential Direct Access Service (31 - 200 kW).

Schedule Page: 304 Line No.: 21 Column: a
Rate Schedule 585 complete title: Large Nonresidential Direct Access Service (201 - 4,000 kW).

Schedule Page: 304 Line No.: 26 Column: a
Rate schedule 89 complete title: Large Nonresidential (>4,000 kW) Standard Service.

Schedule Page: 304 Line No.: 27 Column: a
Rate schedule 85 complete title: Large Nonresidential Standard Service (201 - 4,000 kW)

Schedule Page: 304 Line No.: 28 Column: a
Rate schedule 89 complete title: Large Nonresidential (>4,000 kW) Standard Service.

Schedule Page: 304 Line No.: 29 Column: a
Rate schedule 90 complete title: Large Nonresidential Standard Service (>4,000 kW and Aggregate to >100 MWa)

Schedule Page: 304 Line No.: 30 Column: a
Rate Schedule 489 complete title: Large Nonresidential (>4,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 31 Column: a
Rate Schedule 485 complete title: Large Nonresidential (201 - 4,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 32 Column: a
Rate Schedule 489 complete title: Large Nonresidential (>4,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 33 Column: a
Rate Schedule 585 complete title: Large Nonresidential Direct Access Service (201 - 4,000 kW).

Schedule Page: 304 Line No.: 34 Column: a
Rate Schedule 589 complete title: Large Nonresidential (>4,000 kW) Direct Access Service.

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	NON-RQ SALES:					
2	Arizona Public Service`	SF	WSPP-1	NA	NA	NA
3	ATCO Powre - ATCO	SF	WSPP - 1	NA	NA	NA
4	Avista Corp	SF	WSPP-1	NA	NA	NA
5	Black Hills Power	SF	WSPP-1	NA	NA	NA
6	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
7	Brookfield Energy Marketing LP	SF	WSPP - 1	NA	NA	NA
8	BP Energy Company	SF	PGE-11	NA	NA	NA
9	Burbank, City of	SF	WSPP-1	NA	NA	NA
10	California Independent System Operator	SF	CAISO	NA	NA	NA
11	Calpine Energy Services	SF	EEI	NA	NA	NA
12	Cargill Alliant LLC	SF	WSPP-1	NA	NA	NA
13	Chelan County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
14	Citigroup Energy Inc.	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Clatskanie County PUD, Washington	SF	WSPP-1	NA	NA	NA
2	ConocoPhillips	SF	WSPP - 1	NA	NA	NA
3	CP Energy Marketing	SF	WSPP-1	NA	NA	NA
4	Douglas County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
5	EDF Trading NA	SF	WSPP-1	NA	NA	NA
6	Energy America	SF	WSPP -1	NA	NA	NA
7	Energy Keepes, Inc - ENKP	SF	WSPP-1	NA	NA	NA
8	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
9	Exelon	SF	EEI	NA	NA	NA
10	Glendale, City of	SF	WSPP-1	NA	NA	NA
11	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
12	Gridforce Energy	SF	EEI	NA	NA	NA
13	Iberdrola Renewables	SF	EEI	NA	NA	NA
14	Idaho Power Company	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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 2015/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	JP Morgan	SF	WSPP-1	NA	NA	NA
2	Load Balance Energy	OS	OATT	NA	NA	NA
3	Los Angeles Depart of Water Power	SF	WSPP-1	NA	NA	NA
4	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
5	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
6	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
7	NaturEner	SF	WSPP-1	NA	NA	NA
8	Nevada Power	SF	WSPP-1	NA	NA	NA
9	NextEra Energy Solutions Inc	SF	WSPP-1	NA	NA	NA
10	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
11	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
12	PacifiCorp	LU	PGE-11	NA	NA	NA
13	PacifiCorp	SF	EEI	NA	NA	NA
14	Powerex	SF	PGE-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	PPL Energy Plus	SF	EEI	NA	NA	NA
2	Public Utility District No. 1 of Clark	SF	WSPP-1	NA	NA	NA
3	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
4	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
5	Redding, City of	SF	WSPP-1	NA	NA	NA
6	Roseville, City of	SF	WSPP-1	NA	NA	NA
7	Sacramento Municipal Utility Distric	SF	WSPP-1	NA	NA	NA
8	San Diego Gas & Electric	SF	WSPP-1	NA	NA	NA
9	Seattle City Light	SF	WSPP-1	NA	NA	NA
10	Shell Energy NA	SF	PGE-11	NA	NA	NA
11	Snohomish County PUD Washington	SF	WSPP-1	NA	NA	NA
12	Southern California Edison	SF	EEI	NA	NA	NA
13	Tacoma, City of	SF	WSPP-1	NA	NA	NA
14	Talen Energy	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 2015/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Tenaska	SF	WSPP-1	NA	NA	NA
2	The Energy Authority	SF	WSPP-1	NA	NA	NA
3	TransAlta Energy Marketing	SF	EEI	NA	NA	NA
4	TransCanada Power	SF	WSPP-1	NA	NA	NA
5	Turlock Boardman Revenue	SF	WSPP-1	NA	NA	NA
6	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
7	Tuscon Electric Power Company	SF	WSPP-1	NA	NA	NA
8	Vitol Inc.	SF	WSPP-1	NA	NA	NA
9	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
10						
11	Direct Access Deferral - 2015			NA	NA	NA
12	Direct Access Amortization - 2014			NA	NA	NA
13	Direct Access Amortization - 2013			NA	NA	NA
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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 2015/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Non-RQ Sales:					
2	Portland General Electric Company	SF	OA96137	746	NA	NA
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
1,300		68,800		68,800	2
100		7,800		7,800	3
8,775		192,572		192,572	4
1,035		30,120		30,120	5
102,159		2,727,519		2,727,519	6
2,600		51,150		51,150	7
114,618		3,246,906		3,246,906	8
7,806		327,847		327,847	9
1,283,406		36,147,145		36,147,145	10
9,135		202,532		202,532	11
30,427		829,736		829,736	12
406		8,987		8,987	13
61,373		1,828,240		1,828,240	14
0	0	0	0	0	
3,182,092	4,796,703	103,100,953	1,858,565	109,756,221	
3,182,092	**4,796,703**	**103,100,953**	**1,858,565**	**109,756,221**	

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.
433		10,330		10,330	1
800		28,200		28,200	2
775		23,350		23,350	3
1,090		31,380		31,380	4
173,050		5,121,860		5,121,860	5
809		9,506		9,506	6
70		1,990		1,990	7
4,176		105,024		105,024	8
9,752		268,830		268,830	9
535		18,468		18,468	10
8,657		236,230		236,230	11
31		1,552		1,552	12
77,967		2,154,278		2,154,278	13
23,009		757,642		757,642	14
0	0	0	0	0	
3,182,092	4,796,703	103,100,953	1,858,565	109,756,221	
3,182,092	**4,796,703**	**103,100,953**	**1,858,565**	**109,756,221**	

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.
45,382		1,231,793		1,231,793	1
25,188			626,012	626,012	2
6,225		656,744		656,744	3
51,595		1,348,886		1,348,886	4
14,125		430,760		430,760	5
89,797		2,698,517		2,698,517	6
10		390		390	7
3,813		210,768		210,768	8
1,931		49,623		49,623	9
39,376		987,207		987,207	10
690		23,940		23,940	11
17,000			88,681	88,681	12
81,759		2,139,360		2,139,360	13
15,582		288,281		288,281	14
0	0	0	0	0	
3,182,092	4,796,703	103,100,953	1,858,565	109,756,221	
3,182,092	**4,796,703**	**103,100,953**	**1,858,565**	**109,756,221**	

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 2015/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.
5,748		134,697		134,697	1
2,907		84,380		84,380	2
109,710		3,311,363		3,311,363	3
20,864		541,081		541,081	4
11,409		295,148		295,148	5
1,505		56,113		56,113	6
119,739		3,247,716		3,247,716	7
800		18,600		18,600	8
55,731		1,489,303		1,489,303	9
27,017		637,913		637,913	10
11,650		305,615		305,615	11
160,520		4,986,818		4,986,818	12
4,329		109,064		109,064	13
8,598		221,867		221,867	14
0	0	0	0	0	
3,182,092	4,796,703	103,100,953	1,858,565	109,756,221	
3,182,092	**4,796,703**	**103,100,953**	**1,858,565**	**109,756,221**	

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.
479		502,152		502,152	1
11,384		295,785		295,785	2
86,783		2,556,924		2,556,924	3
18,928		792,567		792,567	4
		12,785,072		12,785,072	5
142,967		4,633,992		4,633,992	6
3,619		145,102		145,102	7
41,389		1,425,808		1,425,808	8
1		22		22	9
					10
			645,075	645,075	11
			563,947	563,947	12
			-65,150	-65,150	13
					14
0	0	0	0	0	
3,182,092	4,796,703	103,100,953	1,858,565	109,756,221	
3,182,092	**4,796,703**	**103,100,953**	**1,858,565**	**109,756,221**	

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
19,248	4,796,703	19,588		4,816,291	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
3,182,092	4,796,703	103,100,953	1,858,565	109,756,221	
3,182,092	**4,796,703**	**103,100,953**	**1,858,565**	**109,756,221**	

Schedule Page: 310.2 Line No.: 2 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: 310.2 Line No.: 12 Column: j

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

Schedule Page: 310.4 Line No.: 5 Column: i

Represents the net value of sale of 10 percent of PGE's Boardman Coal Plant to Turlock Irrigation District.

Schedule Page: 310.4 Line No.: 11 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: 310.4 Line No.: 12 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: 310.4 Line No.: 13 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.: 2 Column: a

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

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,824,281	2,261,040
5	(501) Fuel	91,855,769	95,128,264
6	(502) Steam Expenses	7,020,787	6,652,434
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	8,406,229	10,234,615
11	(507) Rents	40,272	60,036
12	(509) Allowances		113,328
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	110,147,338	114,449,717
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,245,737	1,154,943
16	(511) Maintenance of Structures	1,466,174	1,468,330
17	(512) Maintenance of Boiler Plant	5,747,847	7,935,735
18	(513) Maintenance of Electric Plant	15,367,331	19,692,450
19	(514) Maintenance of Miscellaneous Steam Plant	970,770	1,003,944
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	24,797,859	31,255,402
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	134,945,197	145,705,119
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	821,428	630,058
45	(536) Water for Power	557,345	540,191
46	(537) Hydraulic Expenses	5,975,478	5,094,411
47	(538) Electric Expenses	1,110,068	1,024,224
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,680,908	3,633,678
49	(540) Rents	737,026	753,477
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	11,882,253	11,676,039
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	920,238	524,048
54	(542) Maintenance of Structures	316	8,456
55	(543) Maintenance of Reservoirs, Dams, and Waterways	554,625	1,857,006
56	(544) Maintenance of Electric Plant	1,135,192	1,350,764
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,102,573	1,562,541
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	3,712,944	5,302,815
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	15,595,197	16,978,854

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 2015/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	3,840,358	2,893,680
63	(547) Fuel	183,374,016	156,007,795
64	(548) Generation Expenses	6,544,502	5,399,377
65	(549) Miscellaneous Other Power Generation Expenses	8,075,822	5,199,404
66	(550) Rents	447,761	286,118
67	TOTAL Operation (Enter Total of lines 62 thru 66)	202,282,459	169,786,374
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	775,598	1,533,108
70	(552) Maintenance of Structures	469,781	376,597
71	(553) Maintenance of Generating and Electric Plant	43,705,537	32,173,922
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	556,621	373,821
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	45,507,537	34,457,448
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	247,789,996	204,243,822
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	325,139,822	414,524,300
77	(556) System Control and Load Dispatching	69,545	74,735
78	(557) Other Expenses	17,638,596	16,533,641
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	342,847,963	431,132,676
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	741,178,353	798,060,471
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,214,043	4,152,570
84			
85	(561.1) Load Dispatch-Reliability	14,759	13,201
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	577,320	589,795
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,051,058	920,494
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	29,989	124,864
90	(561.6) Transmission Service Studies	739	
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	149,097	216,775
94	(563) Overhead Lines Expenses	15,293	26,629
95	(564) Underground Lines Expenses		2,888
96	(565) Transmission of Electricity by Others	81,338,058	82,339,358
97	(566) Miscellaneous Transmission Expenses	4,873,194	2,797,510
98	(567) Rents	2,458,627	2,578,304
99	TOTAL Operation (Enter Total of lines 83 thru 98)	95,722,177	93,762,388
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	42,238	48,555
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	656,180	1,000,377
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,051,562	1,317,234
108	(571) Maintenance of Overhead Lines	614,453	437,575
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	5,315	1,096
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,369,748	2,804,837
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	98,091,925	96,567,225

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 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	18,270,237	18,457,253
135	(581) Load Dispatching	1,628,648	1,818,721
136	(582) Station Expenses	925,124	1,012,425
137	(583) Overhead Line Expenses	1,604,180	1,468,773
138	(584) Underground Line Expenses	2,717,292	2,822,869
139	(585) Street Lighting and Signal System Expenses	691,347	204,822
140	(586) Meter Expenses	3,199,250	3,713,534
141	(587) Customer Installations Expenses	2,985,514	3,049,623
142	(588) Miscellaneous Expenses	8,360,066	11,526,163
143	(589) Rents	1,602,504	1,608,235
144	TOTAL Operation (Enter Total of lines 134 thru 143)	41,984,162	45,682,418
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	63,739	111,615
147	(591) Maintenance of Structures	180,978	138,981
148	(592) Maintenance of Station Equipment	4,605,837	4,407,846
149	(593) Maintenance of Overhead Lines	40,218,842	38,122,269
150	(594) Maintenance of Underground Lines	5,881,927	5,055,021
151	(595) Maintenance of Line Transformers	709,378	605,339
152	(596) Maintenance of Street Lighting and Signal Systems	1,055,252	1,370,196
153	(597) Maintenance of Meters	49,201	188,834
154	(598) Maintenance of Miscellaneous Distribution Plant	6,668,116	4,156,684
155	TOTAL Maintenance (Total of lines 146 thru 154)	59,433,270	54,156,785
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	101,417,432	99,839,203
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	752,915	739,908
161	(903) Customer Records and Collection Expenses	43,336,811	39,382,359
162	(904) Uncollectible Accounts	5,517,924	6,899,174
163	(905) Miscellaneous Customer Accounts Expenses	5,092,796	4,809,473
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	54,700,446	51,830,914

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	12,769,301	12,086,884
169	(909) Informational and Instructional Expenses	2,288,709	2,091,727
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	15,058,010	14,178,611
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	60,379,263	58,438,223
182	(921) Office Supplies and Expenses	18,629,826	17,806,181
183	(Less) (922) Administrative Expenses Transferred-Credit	9,387,410	9,527,094
184	(923) Outside Services Employed	8,455,706	7,080,592
185	(924) Property Insurance	5,163,737	4,516,221
186	(925) Injuries and Damages	5,181,555	2,418,111
187	(926) Employee Pensions and Benefits	61,127,470	59,935,856
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	8,003,274	7,170,660
190	(929) (Less) Duplicate Charges-Cr.	2,244,766	2,263,775
191	(930.1) General Advertising Expenses	426,149	560,593
192	(930.2) Miscellaneous General Expenses	9,170,808	8,482,432
193	(931) Rents	4,148,929	4,680,348
194	TOTAL Operation (Enter Total of lines 181 thru 193)	169,054,541	159,298,348
195	Maintenance		
196	(935) Maintenance of General Plant	2,743,739	2,473,930
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	171,798,280	161,772,278
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,182,244,446	1,222,248,702

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 2015/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)	Average Monthly CP Demand (f)
1	ATCO Power	SF	WSPP-1	NA	NA	NA
2	Avista Corp. - AVWP (was WWP)	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	Burbank, City of	SF	WSPP-1	NA	NA	NA
8	California Independent System Operator	SF	CAISO	NA	NA	NA
9	Calpine Energy Services	SF	PGE-11	NA	NA	NA
10	Cargill Alliant LLC	SF	WSPP-1	NA	NA	NA
11	Chelan County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
12	Citigroup Energy	SF	WSPP-1	NA	NA	NA
13	Clatskanie County PUD	SF	WSPP-1	NA	NA	NA
14	ConocoPhillips	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 2015/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	Conduit 3 Hydro	LU	201.00	NA	NA	NA
2	Covanta Marion	LU	QF83-118	NA	NA	NA
3	CP Energy Marketing (US)	SF	WSPP-1	NA	NA	NA
4	Douglas County, PUD No. 1, Washington	LU	Wells	NA	NA	NA
5	Douglas County, PUD No. 1, Washington	LF	Wells	NA	NA	NA
6	Douglas County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
7	EDF Trading North America, LLC	SF	WSPP-1	NA	NA	NA
8	Energy America	SF	WSPP-1	NA	NA	NA
9	Enmax	SF	PGE-11	NA	NA	NA
10	Energy Keepers, Inc. - ENKP	SF	WSPP-1	NA	NA	NA
11	ESI Vansycle Partners, LP	LU	WSPP-1	NA	NA	NA
12	Eugene Water & Electric Board	LU	WSPP-1	10	10	10
13	Eugene Water & Electric Board	LU	ER94-717	NA	NA	NA
14	Eugene Water & Electric Board	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 2015/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	Exelon Generation Co.	SF	WSPP-1	NA	NA	NA
2	Forest Glen Oaks Biomass	LU	FGO	NA	NA	NA
3	Glendale, City of	SF	WSPP-1	NA	NA	NA
4	Grant County, PUD No. 2, Washington	LU	Wanapum	NA	NA	NA
5	Grant County, PUD No. 2, Washington	LU	Priest Rapids	NA	NA	NA
6	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
7	Iberdrola Renewables	SF	PGE-11	NA	NA	NA
8	Iberdrola Renewables	LU	PGE-11	NA	NA	NA
9	Iberdrola Renewables	LU	PGE-11	100	100	100
10	Idaho Falls, City of	SF	WSPP-1	NA	NA	NA
11	Idaho Power Company	SF	WSPP-1	NA	NA	NA
12	JC Biomethane	LF	JCBIO	NA	NA	NA
13	Load Balance Energy	OS	OATT	NA	NA	NA
14	Los Angeles Depart Water Power	SF	WSPP-1	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
2	Morgan Stanley Capital Group	SF	PGE-11	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 Wasco PUD Hydro	LU	NWASCO	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	PacifiCorp	RQ	PP&L 147	NA	NA	NA
12	PacifiCorp	SF	PGE-11	NA	NA	NA
13	PaTu Wind	LU	WSPP-1	NA	NA	NA
14	Portland, City of	LU	#2821	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 2015/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	Powerex	SF	PGE-11	NA	NA	NA
2	PPL Energy Plus	SF	PGE-11	NA	NA	NA
3	PRC - Coffin Butte Biomass	LU	PRC	NA	NA	NA
4	Public Utility District No. 1 of Clark	SF	WSPP-1	NA	NA	NA
5	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
6	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
7	Roseville, City of	SF	WSPP-1	NA	NA	NA
8	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
9	Seattle City Light	SF	WSPP-1	NA	NA	NA
10	Shell Energy	SF	WSPP-1	NA	NA	NA
11	Snohomish County, PUD No. 1, Washingtn	SF	WSPP-1	NA	NA	NA
12	Southern California Edison	SF	PGE-11	NA	NA	NA
13	Spokane Energy, LLC	LF	PGE-82	150	150	150
14	Spokane Energy, LLC	EX	PGE-82	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 2015/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	Tacoma, City of	SF	WSPP-1	NA	NA	NA
2	Talen Energy	SF	PGE-11	NA	NA	NA
3	Tenaska	SF	WSPP-1	NA	NA	NA
4	The Energy Authority	SF	WSPP-1	NA	NA	NA
5	Tillamook Biomass	LU	TBIO	NA	NA	NA
6	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
7	TransAlta Energy Marketing	LF	PGE-11	NA	NA	NA
8	TransCanada Energy Marketing	SF	WSPP-1	NA	NA	NA
9	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
10	Vitol Inc	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 2015/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)	Average Monthly CP Demand (f)
1	Country Village Estates	OS	201	NA	NA	NA
2	Domaine Drouhin	OS	201	NA	NA	NA
3	Von Land Co	OS	201	NA	NA	NA
4	Minikahada Hydropower Co	OS	201	NA	NA	NA
5	Starbucks Properties	OS	201	NA	NA	NA
6	SunWay LLC	LU	201	NA	NA	NA
7	Solar Payment Option	OS	215-217	NA	NA	NA
8	Tualatin Valley Water Dist	OS	201	NA	NA	NA
9	Oregon Heat	OS	203	NA	NA	NA
10	Load Curtailment Program			NA	NA	NA
11	Margin on Electric Financials			NA	NA	NA
12	Reserve Trading Credit Risk			NA	NA	NA
13	Green Power			NA	NA	NA
14	REC Retirement Expense			NA	NA	NA
	Total					

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	Carbon Allowance Expense			NA	NA	NA
2						
3	Non-cash exchanges					
4	Energy Storage Expense					
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,208				242,314		242,314	1
117,318				4,207,697		4,207,697	2
2,028							3
1,891				190,506		190,506	4
490,839				10,835,634		10,835,634	5
17,728				426,376		426,376	6
767				7,094		7,094	7
83,261				2,176,938		2,176,938	8
126,284				3,455,860		3,455,860	9
82,199				1,786,234		1,786,234	10
33,098				773,269		773,269	11
1,200				31,000		31,000	12
6,332				115,092		115,092	13
5,200				151,180		151,180	14
9,841,229	440,265	439,113	21,717,000	261,874,599	41,548,223	325,139,822	

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 2015/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)	
89				5,714		5,714	1
86,604				1,850,275		1,850,275	2
650				21,250		21,250	3
745,586				10,412,310		10,412,310	4
195,081				6,594,132		6,594,132	5
39,288				883,607		883,607	6
71,455				1,605,304		1,605,304	7
800				88,000		88,000	8
1,350				29,540		29,540	9
476				7,250		7,250	10
62,863				3,828,201		3,828,201	11
			84,000			84,000	12
-561							13
51,310				909,277		909,277	14
9,841,229	440,265	439,113	21,717,000	261,874,599	41,548,223	325,139,822	

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)	
55,829				1,187,557		1,187,557	1
1,134				68,208		68,208	2
160				3,190		3,190	3
385,529							4
375,030				18,052,114		18,052,114	5
270,858				4,941,151		4,941,151	6
325,054				7,409,522		7,409,522	7
208,973				11,273,263		11,273,263	8
			2,445,000			2,445,000	9
50				1,100		1,100	10
59,292				1,336,029		1,336,029	11
8,160				473,996		473,996	12
22,755				634,870		634,870	13
3,000				229,825		229,825	14
9,841,229	440,265	439,113	21,717,000	261,874,599	41,548,223	325,139,822	

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)	
96,725				2,306,923		2,306,923	1
127,159				3,047,326		3,047,326	2
50				-19,400		-19,400	3
2,000				39,450		39,450	4
261,116				7,684,001		7,684,001	5
10,381				231,409		231,409	6
39,587				2,102,991		2,102,991	7
34,922				719,281		719,281	8
12,141				217,656		217,656	9
10,541				960,831		960,831	10
9,921				1,006,462		1,006,462	11
111,924				2,464,380		2,464,380	12
31,039				2,102,916		2,102,916	13
65,605				3,044,377		3,044,377	14
9,841,229	440,265	439,113	21,717,000	261,874,599	41,548,223	325,139,822	

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)	
249,563				7,511,392		7,511,392	1
40,363				809,195		809,195	2
47,078				2,971,522		2,971,522	3
38,386				734,704		734,704	4
154,103				3,563,126		3,563,126	5
400				3,600		3,600	6
19				370		370	7
4,751				132,084		132,084	8
250,860				5,257,224		5,257,224	9
2,100,890				48,585,403		48,585,403	10
115,299				2,112,768		2,112,768	11
103,873				1,694,085		1,694,085	12
			19,188,000			19,188,000	13
	440,265	439,113					14
9,841,229	440,265	439,113	21,717,000	261,874,599	41,548,223	325,139,822	

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)	
93,628				1,970,435		1,970,435	1
60,245				1,518,491		1,518,491	2
9,571				121,746		121,746	3
112,140				2,127,864		2,127,864	4
7,170				272,529		272,529	5
137,434				3,377,759		3,377,759	6
875,179				37,187,801		37,187,801	7
70,617				1,586,010		1,586,010	8
37,287				667,292		667,292	9
36,000				756,088		756,088	10
518,359				16,122,763		16,122,763	11
75				1,350		1,350	12
1,335				134,438		134,438	13
60				4,286		4,286	14
9,841,229	440,265	439,113	21,717,000	261,874,599	41,548,223	325,139,822	

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)	
45				2,877		2,877	1
90				3,202		3,202	2
197				8,285		8,285	3
264				10,719		10,719	4
30				2,429		2,429	5
2,328				198,578		198,578	6
10,064				266,494		266,494	7
94				4,208		4,208	8
1,153					42,041	42,041	9
					1,132,822	1,132,822	10
					32,158,351	32,158,351	11
					50,115	50,115	12
					7,736,301	7,736,301	13
					170,825	170,825	14
9,841,229	440,265	439,113	21,717,000	261,874,599	41,548,223	325,139,822	

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)	
					238,476	238,476	1
							2
					19,292	19,292	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
9,841,229	440,265	439,113	21,717,000	261,874,599	41,548,223	325,139,822	

Schedule Page: 326.1 Line No.: 4 Column: c
Non jurisdictional utilities.

Schedule Page: 326.1 Line No.: 5 Column: b
The Douglas County contract expires on 8/31/18.

Schedule Page: 326.1 Line No.: 13 Column: g
Represents net of energy generated at EWEB's Stone Creek facility within PGE's control area and energy delivered to EWEB.

Schedule Page: 326.1 Line No.: 14 Column: c
Non jurisdictional utilities.

Schedule Page: 326.2 Line No.: 4 Column: c
Non jurisdictional utilities.

Schedule Page: 326.2 Line No.: 13 Column: a
Represents the value of energy delivered to the PGE control area from Electricity Service Suppliers in excess of the ESS's actual load within the PGE control area.

Schedule Page: 326.3 Line No.: 5 Column: b
The NextEra contract expired 12/31/15.

Schedule Page: 326.4 Line No.: 11 Column: c
Non jurisdictional utilities.

Schedule Page: 326.4 Line No.: 13 Column: b
The Spokane Energy, LLC contract expires on 12/31/16.

Schedule Page: 326.5 Line No.: 7 Column: b
The TransAlta Energy Marketing contract expires on 9/30/16.

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

Schedule Page: 326.6 Line No.: 10 Column: l
Power purchased under Load Curtailment Program.

Schedule Page: 326.6 Line No.: 11 Column: l
Margin on electric financial transactions.

Schedule Page: 326.6 Line No.: 12 Column: l
Reserve for trading credit risk.

Schedule Page: 326.6 Line No.: 13 Column: l
Consists of expenses related to the purchase of RECs and development of future renewable resources for PGE's Portfolio Options programs. Such expenses are fully offset by customer

revenues.

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

Expense of annual REC retirement to meet RPS compliance.

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

Expense of carbon allowances retired to comply with California's Cap-and-Trade Program.

Schedule Page: 326.7 Line No.: 4 Column: g

There are no costs recorded in Account 555.1, Power Purchased for Storage, as the Company did not purchase power for storage purposes during the year.

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Avista Corp. Washington Water Power	Avista Corp.	Balancing Authority of N Calif	LFP
2	Avista Corp. Washington Water Power	Avista Corp.	Balancing Authority of N Calif	LFP
3	Avista Corp. Washington Water Power	Bonneville Power Administration	CAISO	NF
4	Bonneville Power Administration	Bonneville Power Administration	Balancing Authority of N Calif	NF
5	Bonneville Power Administration	Bonneville Power Administration	CAISO	NF
6	Bonneville Power Administration	Bonneville Power Administration	Portland General Electric	FNO
7	Bonneville Power Administration	Bonneville Power Administration	Portland General Electric	NF
8	Bonneville Power Administration	Bonneville Power Administration	Western Oregon Electric Coop	OLF
9	Bonneville Power Administration	Bonneville Power Administration	Other TVI Pumps	OLF
10	Bonneville Power Administration	Bonneville Power Administration	Canby People's Utility District	OLF
11	Bonneville Power Administration	Bonneville Power Administration	Columbia River PUD	OLF
12	EDF Trading North America LLC	Bonneville Power Administration	CAISO	NF
13	Exelon Generation Company LLC	Bonneville Power Administration	Balancing Authority of N Calif	LFP
14	Exelon Generation Company LLC	Bonneville Power Administration	CAISO	LFP
15	Exelon Generation Company LLC	Bonneville Power Administration	CAISO	NF
16	Exelon Generation Company LLC	Bonneville Power Administration	Portland General Electric	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.	Bonneville Power Administration	PacifiCorp	NF
20	Macquarie Energy LLC	Bonneville Power Administration	CAISO	NF
21	Macquarie Energy LLC	Bonneville Power Administration	CAISO	SFP
22	Macquarie Energy LLC	CAISO	Bonneville Power Administration	SFP
23	Macquarie Energy LLC	CAISO	Bonneville Power Administration	NF
24	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Balancing Authority of N Calif	NF
25	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Balancing Authority of N Calif	LFP
26	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Balancing Authority of N Calif	SFP
27	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Balancing Authority of N Calif	OS
28	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	CAISO	OS
29	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	CAISO	NF
30	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	CAISO	LFP
31	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp	NF
32	Morgan Stanley Capital Group Inc.	CAISO	Bonneville Power Administration	NF
33	Nextera Energy Power Marketing, LLC	Bonneville Power Administration	CAISO	NF
34	Noble Americas Energy Solutions	Bonneville Power Administration	Portland General Electric	NF
	TOTAL			

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Noble Americas Energy Solutions	Portland General Electric	Portland General Electric	NF
2	Noble Americas Energy Solutions	Portland General Electric	Portland General Electric	NF
3	Pacificorp	PacifiCorp	Portland General Electric	OLF
4	Pacificorp	Portland General Electric	PacifiCorp	NF
5	Powerex Corp.	Bonneville Power Administration	Balancing Authority of N Calif	NF
6	Powerex Corp.	Bonneville Power Administration	CAISO	NF
7	Powerex Corp.	Bonneville Power Administration	CAISO	LFP
8	Powerex Corp.	Bonneville Power Administration	PacifiCorp	LFP
9	Powerex Corp.	Bonneville Power Administration	PacifiCorp	NF
10	Powerex Corp.	Bonneville Power Administration	Balancing Authority of N Calif	LFP
11	PUD No. 1 of Cowlitz County			LFP
12	PUD No. 1 of Franklin County			LFP
13	PUD No. 1 of Klickitat County			LFP
14	PUD No. 1 of Lewis County			LFP
15	Puget Sound Energy	Balancing Authority of N Calif	Bonneville Power Administration	LFP
16	Puget Sound Energy	Bonneville Power Administration	Balancing Authority of N Calif	OS
17	Puget Sound Energy	Bonneville Power Administration	Bonneville Power Administration	LFP
18	Puget Sound Energy	Bonneville Power Administration	CAISO	OS
19	Puget Sound Energy	Bonneville Power Administration	CAISO	NF
20	Puget Sound Energy	Bonneville Power Administration	PacifiCorp	OS
21	Puget Sound Energy	CAISO	Bonneville Power Administration	SFP
22	Puget Sound Energy	CAISO	Bonneville Power Administration	LFP
23	Puget Sound Energy	CAISO	Bonneville Power Administration	NF
24	Puget Sound Energy	CAISO	Puget Sound Energy Transmission	OS
25	Seattle City Light Marketing	Balancing Authority of N Calif	Bonneville Power Administration	NF
26	Seattle City Light Marketing	Bonneville Power Administration	Balancing Authority of N Calif	NF
27	Seattle City Light Marketing	Bonneville Power Administration	Bonneville Power Administration	NF
28	Seattle City Light Marketing	Bonneville Power Administration	CAISO	NF
29	Shell Energy North America (US), L.P.	Bonneville Power Administration	Balancing Authority of N Calif	LFP
30	Shell Energy North America (US), L.P.	Bonneville Power Administration	Balancing Authority of N Calif	NF
31	Shell Energy North America (US), L.P.	Bonneville Power Administration	CAISO	LFP
32	Shell Energy North America (US), L.P.	Bonneville Power Administration	CAISO	NF
33	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp	LFP
34	Shell Energy North America (US), L.P.	Bonneville Power Administration	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 2015/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Shell Energy North America (US), L.P.	CAISO	Bonneville Power Administration	NF
2	Shell Energy North America (US), L.P.	CAISO	Bonneville Power Administration	OS
3	Southern California Edison	Bonneville Power Administration	CAISO	NF
4	TNSK	Bonneville Power Administration	Balancing Authority of N Calif	NF
5	TNSK	Bonneville Power Administration	CAISO	NF
6	Turlock Irrigation District	Bonneville Power Administration	Balancing Authority of N Calif	NF
7	The Energy Authority	Balancing Authority of N Calif	Bonneville Power Administration	NF
8	The Energy Authority	Balancing Authority of N Calif	Bonneville Power Administration	OS
9	The Energy Authority	Balancing Authority of N Calif	Bonneville Power Administration	LFP
10	The Energy Authority	Bonneville Power Administration	Balancing Authority of N Calif	OS
11	The Energy Authority	Bonneville Power Administration	Balancing Authority of N Calif	LFP
12	The Energy Authority	Bonneville Power Administration	Balancing Authority of N Calif	NF
13	The Energy Authority	Bonneville Power Administration	CAISO	NF
14	The Energy Authority	Bonneville Power Administration	CAISO	OS
15	The Energy Authority	Bonneville Power Administration	CAISO	LFP
16	The Energy Authority	Bonneville Power Administration	PacifiCorp	LFP
17	The Energy Authority	Bonneville Power Administration	PacifiCorp	OS
18	The Energy Authority	Bonneville Power Administration	PacifiCorp	NF
19	The Energy Authority	CAISO	Bonneville Power Administration	LFP
20	The Energy Authority	CAISO	Bonneville Power Administration	NF
21	The Energy Authority	CAISO	Bonneville Power Administration	OS
22	TransAlta Energy Marketing U.S. Inc.	Bonneville Power Administration	Balancing Authority of N Calif	NF
23	TransAlta Energy Marketing U.S. Inc.	Bonneville Power Administration	CAISO	NF
24	TransAlta Energy Marketing U.S. Inc.	Bonneville Power Administration	CAISO	SFP
25	TransAlta Energy Marketing U.S. Inc.	CAISO	Bonneville Power Administration	NF
26	TransAlta Energy Marketing U.S. Inc.	Bonneville Power Administration	PacifiCorp	NF
27	Accrual			AD
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
8	JohnDay	Malin500		477,820	477,820	1
8	JohnDay	CaptainJack		71,312	71,312	2
8	JohnDay	Malin500		120	120	3
8	JohnDay	CaptainJack		8	8	4
8	JohnDay	Malin500		4,469	4,468	5
8	BPAT.PGE	PGE	176	87,594	87,986	6
8	BPAT.PGE	PGE		4	4	7
72	Various Subs	Various Subs		14,295	12,333	8
72	Various Subs	Various Subs		10,636	9,176	9
72	Various Subs	Various Subs		144,415	124,589	10
72	Various Subs	Various Subs		225,178	194,264	11
8	JohnDay	Malin500		181	181	12
8	JohnDay	CaptainJack		868	868	13
8	JohnDay	Malin500		55,235	55,235	14
8	JohnDay	Malin500		16,134	16,134	15
8	BPAT.PGE	PGE	183,472	95,929	75,483	16
8	KFallsGen	JohnDay		250	250	17
8	JohnDay	Malin500		813	813	18
8	JohnDay	Malin500		54	54	19
8	JohnDay	Malin500		46,125	46,125	20
8	JohnDay	Malin500		981	981	21
8	Malin500	JohnDay		4,000	4,000	22
8	Malin500	JohnDay		800	800	23
8	JohnDay	CaptainJack		9,736	9,736	24
8	JohnDay	CaptainJack		67,212	67,212	25
8	JohnDay	CaptainJack				26
8	JohnDay	CaptainJack		1,933	1,933	27
8	JohnDay	Malin500		497	497	28
8	JohnDay	Malin500		9,981	9,981	29
8	JohnDay	Malin500		10,510	10,510	30
8	JohnDay	Malin500		4	4	31
8	Malin500	JohnDay		330	330	32
8	JohnDay	Malin500		59,254	59,254	33
8	BPAT.PGE	PGE	3,035,757	1,637,782	1,652,142	34
			3,265,562	**6,589,962**	**6,532,762**	

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	BPAT.PGE	PGE	426	230	232	1
8	PGE.INTERNAL	PGE	1,349	728	734	2
Exch	JOHNDAY	Various Subs		4,141	3,993	3
8	PGE	PACW				4
8	JohnDay	CaptainJack		11,873	11,873	5
8	JohnDay	Malin500		19,772	19,772	6
8	JohnDay	Malin500		1,507,419	1,507,419	7
8	JohnDay	Malin500		4,443	4,443	8
8	JohnDay	Malin500		550	550	9
8	JohnDay	CaptainJack		335,446	335,446	10
8	JohnDay	COB				11
8	JohnDay	COB				12
8	JohnDay	COB				13
8	JohnDay	COB				14
8	CaptainJack	JohnDay		50	50	15
8	JohnDay	CaptainJack		100	100	16
8	KFallsGen	JohnDay		2,965	2,965	17
8	JohnDay	Malin500		162	162	18
8	JohnDay	Malin500		60	60	19
8	JohnDay	Malin500		350	350	20
8	Malin500	JohnDay		45	45	21
8	Malin500	JohnDay		6,074	6,074	22
8	Malin500	JohnDay		19,776	19,776	23
8	Malin500	JohnDay		25	25	24
8	CaptainJack	JohnDay		30	30	25
8	JohnDay	CaptainJack		3,708	3,708	26
8	KFallsGen	JohnDay		8	8	27
8	JohnDay	Malin500		760	760	28
8	JohnDay	CaptainJack		58,207	58,207	29
8	JohnDay	CaptainJack		210	210	30
8	JohnDay	Malin500		1,266,271	1,266,271	31
8	JohnDay	Malin500		31,624	31,624	32
8	JohnDay	Malin500		478	478	33
8	BPAT.PGE	PGE	44,382	18,769	21,566	34
			3,265,562	**6,589,962**	**6,532,762**	

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 2015/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	Malin500	JohnDay		36	36	1
8	Malin500	JohnDay		151	151	2
8	JohnDay	Malin500		4,890	4,890	3
8	JohnDay	CaptainJack		37	37	4
8	JohnDay	Malin500		741	741	5
8	JohnDay	CaptainJack		6,846	6,846	6
8	CaptainJack	JohnDay		1,193	1,193	7
8	CaptainJack	JohnDay		1,050	1,050	8
8	CaptainJack	JohnDay		432	432	9
8	JohnDay	CaptainJack		581	581	10
8	JohnDay	CaptainJack		21,944	21,944	11
8	JohnDay	CaptainJack		9,962	9,962	12
8	JohnDay	Malin500		4,264	4,264	13
8	JohnDay	Malin500		371	371	14
8	JohnDay	Malin500		166,473	166,473	15
8	JohnDay	Malin500		483	483	16
8	JohnDay	Malin500		25	25	17
8	JohnDay	Malin500		1,140	1,140	18
8	Malin500	JohnDay		2,802	2,802	19
8	Malin500	JohnDay		2,330	2,330	20
8	Malin500	JohnDay		649	649	21
8	JohnDay	CaptainJack		21	21	22
8	JohnDay	Malin500		13,184	13,184	23
8	JohnDay	Malin500		25	25	24
8	Malin500	JohnDay		1,597	1,597	25
8	JohnDay	Malin500		1	1	26
						27
						28
						29
						30
						31
						32
						33
						34
			3,265,562	**6,589,962**	**6,532,762**	

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.
	559,488		559,488	1
	83,501		83,501	2
	100		100	3
	9		9	4
	4,955		4,955	5
111,616			111,616	6
	4		4	7
	91,752		91,752	8
	29,362		29,362	9
	352,676		352,676	10
	25,757		25,757	11
	301		301	12
	995		995	13
	63,304		63,304	14
	19,578		19,578	15
123,443			123,443	16
	418		418	17
	1,361		1,361	18
	90		90	19
	54,188		54,188	20
	4,259		4,259	21
	17,367		17,367	22
	940		940	23
	13,556		13,556	24
	55,604		55,604	25
	46,455		46,455	26
				27
				28
	13,897		13,897	29
	8,695		8,695	30
	6		6	31
	459		459	32
	58,670		58,670	33
1,965,465			1,965,465	34
2,228,442	**5,785,080**	**243,707**	**8,257,229**	

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 2015/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.
276			276	1
874			874	2
		247,312	247,312	3
	118		118	4
	24,288		24,288	5
	40,447		40,447	6
	1,479,610		1,479,610	7
	4,361		4,361	8
	1,125		1,125	9
	329,258		329,258	10
	64,299		64,299	11
	64,299		64,299	12
	70,729		70,729	13
	70,729		70,729	14
	3,537		3,537	15
				16
	209,755		209,755	17
				18
	68		68	19
				20
	13,600		13,600	21
	429,697		429,697	22
	22,400		22,400	23
				24
	32		32	25
	3,917		3,917	26
	8		8	27
	803		803	28
	56,495		56,495	29
	257		257	30
	1,229,019		1,229,019	31
	38,628		38,628	32
	464		464	33
26,768			26,768	34
2,228,442	**5,785,080**	**243,707**	**8,257,229**	

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.
	44		44	1
				2
	8,097		8,097	3
	47		47	4
	944		944	5
	7,409		7,409	6
	1,278		1,278	7
				8
	144		144	9
				10
	7,338		7,338	11
	10,673		10,673	12
	4,569		4,569	13
				14
	55,668		55,668	15
	162		162	16
				17
	1,221		1,221	18
	937		937	19
	2,496		2,496	20
				21
	26		26	22
	16,310		16,310	23
	50		50	24
	1,976		1,976	25
	1		1	26
		-3,605	-3,605	27
				28
				29
				30
				31
				32
				33
				34
2,228,442	**5,785,080**	**243,707**	**8,257,229**	

Schedule Page: 328 Line No.: 1 Column: d
Contract with Avista Corporation Washington Water Power Division expires 01/01/2023.
Schedule Page: 328 Line No.: 2 Column: d
Contract with Avista Corporation Washington Water Power Division expires 01/01/2023.
Schedule Page: 328 Line No.: 8 Column: d
Contract with Bonneville Power Administration continues until terminated.
Schedule Page: 328 Line No.: 9 Column: d
Contract with Bonneville Power Administration continues until terminated.
Schedule Page: 328 Line No.: 10 Column: d
Contract with Bonneville Power Administration continues until terminated.
Schedule Page: 328 Line No.: 11 Column: d
Contract with Bonneville Power Administration continues until terminated.
Schedule Page: 328 Line No.: 13 Column: d
Contract with Exelon Generation Company LLC expires 01/01/2034.
Schedule Page: 328 Line No.: 14 Column: d
Contract with Exelon Generation Company LLC expires 01/01/2034.
Schedule Page: 328 Line No.: 25 Column: d
Contract with Morgan Stanley Capital Group Inc expires 01/01/2034.
Schedule Page: 328 Line No.: 27 Column: d
Represents non-billed redirected MWHs of Morgan Stanley Capital Group Inc’s service.
Schedule Page: 328 Line No.: 28 Column: d
Represents non-billed redirected MWHs of Morgan Stanley Capital Group Inc’s service.
Schedule Page: 328 Line No.: 30 Column: d
Contract with Morgan Stanley Capital Group Inc expires 01/01/2034.
Schedule Page: 328.1 Line No.: 3 Column: d
Exchange agreement with Pacificorp.
Schedule Page: 328.1 Line No.: 3 Column: e
Exchange agreement with Pacificorp. No tariff applicable to exchange agreement.
Schedule Page: 328.1 Line No.: 7 Column: d
Contract with Powerex Corp expires 06/01/2018.
Schedule Page: 328.1 Line No.: 8 Column: d
Contract with Powerex Corp expires 06/01/2018.
Schedule Page: 328.1 Line No.: 10 Column: d
Contract with Powerex Corp expires 06/01/2018.
Schedule Page: 328.1 Line No.: 11 Column: b
Represents the reassignment of Public Utility District No. 1 of Cowlitz County's transmission capacity rights.
Schedule Page: 328.1 Line No.: 11 Column: c
Represents the reassignment of Public Utility District No. 1 of Cowlitz County's transmission capacity rights.
Schedule Page: 328.1 Line No.: 11 Column: d
Contract with PUD No 1 of Cowlitz County expires 01/01/2034.
Schedule Page: 328.1 Line No.: 12 Column: b
Represents the reassignment of Public Utility District No. 1 of Franklin County's transmission capacity rights.
Schedule Page: 328.1 Line No.: 12 Column: c
Represents the reassignment of Public Utility District No. 1 of Franklin County's transmission capacity rights.
Schedule Page: 328.1 Line No.: 12 Column: d
Contract with PUD No 1 of Franklin County expires 01/01/2034.
Schedule Page: 328.1 Line No.: 13 Column: b
Represents the reassignment of Public Utility District No. 1 of Klickitat County's transmission capacity rights.
Schedule Page: 328.1 Line No.: 13 Column: c

Represents the reassignment of Public Utility District No. 1 of Klickitat County's transmission capacity rights.

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

Contract with PUD No 1 of Klickitat County expires 01/01/2034.

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

Represents the reassignment of Public Utility District No. 1 of Lewis County's transmission capacity rights.

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

Represents the reassignment of Public Utility District No. 1 of Lewis County's transmission capacity rights.

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

Contract with PUD No 1 of Lewis County expires 01/01/2034.

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

Contract with Puget Sound Energy expires 01/01/2017.

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

Represents non-billed redirected MWHs of Puget Sound Energy’s service.

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

Contract with Puget Sound Energy expires 01/01/2017.

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

Represents non-billed redirected MWHs of Puget Sound Energy’s service.

Schedule Page: 328.1 Line No.: 20 Column: d

Represents non-billed redirected MWHs of Puget Sound Energy’s service.

Schedule Page: 328.1 Line No.: 22 Column: d

Contract with Puget Sound Energy expires 01/01/2017.

Schedule Page: 328.1 Line No.: 24 Column: d

Represents non-billed redirected MWHs of Puget Sound Energy’s service.

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

Contract with Shell Energy North America (US) LP expires 01/01/2022.

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

Contract with Shell Energy North America (US) LP expires 01/01/2022.

Schedule Page: 328.1 Line No.: 33 Column: d

Contract with Shell Energy North America (US) LP expires 01/01/2022.

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

Represents non-billed redirected MWHs of Shell Energy North America (US) LP’s service.

Schedule Page: 328.2 Line No.: 8 Column: d

Represents non-billed redirected MWHs of The Energy Authority's service.

Schedule Page: 328.2 Line No.: 9 Column: d

Contract with The Energy Authority expires 01/01/2034.

Schedule Page: 328.2 Line No.: 10 Column: d

Represents non-billed redirected MWHs of The Energy Authority's service.

Schedule Page: 328.2 Line No.: 11 Column: d

Contract with The Energy Authority expires 01/01/2034.

Schedule Page: 328.2 Line No.: 14 Column: d

Represents non-billed redirected MWHs of The Energy Authority's service.

Schedule Page: 328.2 Line No.: 15 Column: d

Contract with The Energy Authority expires 01/01/2034.

Schedule Page: 328.2 Line No.: 16 Column: d

Contract with The Energy Authority expires 01/01/2034.

Schedule Page: 328.2 Line No.: 17 Column: d

Represents non-billed redirected MWHs of The Energy Authority's service.

Schedule Page: 328.2 Line No.: 19 Column: d

Contract with The Energy Authority expires 01/01/2034.

Schedule Page: 328.2 Line No.: 21 Column: d

Represents non-billed redirected MWHs of The Energy Authority's service.

Schedule Page: 328.2 Line No.: 27 Column: d

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

Schedule Page: 328.2 Line No.: 27 Column: m

Represents the difference between actual transmission revenue for the year as reflected on the individual line items within this schedule, and the accruals credited during the year 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 2015/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp	NF	26,134	26,134		79,693		79,693
2	Bonneville Power Admin	LFP			56,502,150			56,502,150
3	Bonneville Power Admin	OS					22,093,565	22,093,565
4	Bonneville Power Admin	SFP	51,251	51,251		135,862		135,862
5	Bonneville Power Admin	NF	21,470	21,470		73,320		73,320
6	Columbia River PUD	NF	11	11		3,991		3,991
7	Idaho Power Company	NF	20,600	20,600		109,328		109,328
8	Los Angeles Dept. Water	NF	850	850		8,545		8,545
9	McMinnville Water & Lig	NF	823	823		7,467		7,467
10	Montana, State of	OS					1,189,107	1,189,107
11	NorthWestern Energy	NF	202,179	202,179		917,067		917,067
12	Northwest Power Pool	OS					1,979	1,979
13	NV Energy	NF	4,308	4,308		33,909		33,909
14	PacifiCorp	OS					103,752	103,752
15	PacifiCorp	NF	9,542	9,542		66,521		66,521
16	Puget Sound Energy	NF	588	588		4,018		4,018
	TOTAL		338,826	338,826	56,502,150	1,447,505	23,388,403	81,338,058

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 2015/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	Sacramento Municipal	LFP	591	591		6,755		6,755
2	Seattle City Light	NF	141	141		176		176
3	Sierra Nevada	NF	88	88		264		264
4	WALC - Desert SW Region	NF	250	250		589		589
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		338,826	338,826	56,502,150	1,447,505	23,388,403	81,338,058

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

Represents the Bonneville Power Administration PTP contracts.

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

Represents Bonneville Power Administration Ancillary Transmission Services.

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.: 12 Column: g

Represents Ancillary Services under the Pacific Northwest Coordinating Agreement.

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

Represents PacifiCorp's Linneman Transmission Services.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,219,941
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	1,283,046
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,707,119
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Involuntary Severance	-95,811
7	Directors Pension	97,213
8	Directors Fees & Expenses	122,804
9	Directors and Officers Expenses	2,484,927
10	Misc Admin Expenses	1,130,461
11	Colstrip-PPL Montana	73,311
12	Internal & External Reporting	117,703
13	Bull Run PME-Decommissioning	22,446
14	Misc Admin R&D Expenses	7,648
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	9,170,808

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 2015/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			38,364,891		38,364,891
2	Steam Production Plant	26,391,777	4,828,988			31,220,765
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	15,806,131	69			15,806,200
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	69,759,747	184,303			69,944,050
7	Transmission Plant	9,071,063	1			9,071,064
8	Distribution Plant	97,453,575	13,149			97,466,724
9	Regional Transmission and Market Operation					
10	General Plant	33,915,302	263			33,915,565
11	Common Plant-Electric					
12	TOTAL	252,397,595	5,026,773	38,364,891		295,789,259

B. Basis for Amortization Charges

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	311-01 Boardman	140,836	40.00	-10.00	19.67	Life Span - 2020	5.08
13	311-01 Colstrip	114,980	90.00	-5.00	3.68	S1.5	27.17
14	312-00 Boardman	356,105	40.00	-10.00	19.67	Life Span - 2020	5.08
15	312-00 Colstrip	229,441	65.00	-5.00	3.76	R3	26.60
16	314-00 Boardman	115,881	40.00	-10.00	19.67	Life Span - 2020	5.08
17	314-00 Colstrip	73,163	60.00	-5.00	4.22	S0.5	23.70
18	315-00 Boardman	31,763	40.00	-10.00	19.67	Life Span - 2020	5.08
19	315-00 Colstrip	23,504	60.00	-5.00	4.14	R2.5	24.15
20	316-01 Boardman	8,521	40.00	-10.00	19.67	Life Span - 2020	5.08
21	316-01 Colstrip	6,315	55.00	-5.00	4.39	R1	22.78
22	317-00 Boardman	47,635				SQ	
23	317-00 Boardman	16,635				SQ	
24	SUBTOTAL STEAM	1,164,779					
25	330-11 Round Butte	2,212	75.00		3.13	SQ	32.00
26	331-00 Faraday	6,507	100.00	-50.00	2.64	R2.5	37.88
27	331-00 North Fork	8,767	100.00	-115.00	2.60	R2.5	38.46
28	331-00 Oak Grove	2,612	100.00	-50.00	2.74	R2.5	36.50
29	331-00 OG Timothy Lake	5,197	100.00	-50.00	2.58	R2.5	38.76
30	331-00 Pelton	6,078	100.00	-110.00	2.64	R2.5	37.88
31	331-00 River Mill	3,087	100.00	-80.00	2.84	R2.5	35.21
32	331-00 Round Butte	11,636	100.00	-75.00	2.64	R2.5	37.88
33	331-00 Sullivan	9,367	100.00	-30.00	4.63	R2.5	21.60
34	332-00 Faraday	25,710	100.00	-50.00	2.57	R3	38.91
35	332-00 North Fork	82,475	100.00	-115.00	2.66	R3	37.59
36	332-00 Oak Grove	19,013	100.00	-50.00	2.53	R3	39.53
37	332-00 OG Timothy Lake	5,238	100.00	-50.00	2.77	R3	36.10
38	332-00 Pelton	10,571	100.00	-110.00	2.74	R3	36.50
39	332-00 River Mill	54,796	100.00	-80.00	2.49	R3	40.16
40	332-00 Round Butte	111,752	100.00	-75.00	2.49	R3	40.16
41	332-00 Sullivan	23,570	100.00	-30.00	4.54	R3	22.03
42	333-00 Faraday	6,744	90.00	-50.00	2.71	S1	36.90
43	333-00 North Fork	6,900	90.00	-110.00	2.90	S1	34.48
44	333-00 Oak Grove	6,507	90.00	-50.00	2.71	S1	36.90
45	333-00 Pelton	4,106	90.00	-100.00	3.06	S1	32.68
46	333-00 River Mill	5,926	90.00	-80.00	2.69	S1	37.17
47	333-00 Round Butte	21,073	90.00	-70.00	2.68	S1	37.31
48	333-00 Sullivan	9,416	90.00	-30.00	4.64	S1	21.55
49	334-00 Faraday	2,581	60.00	-30.00	3.14	R2.5	31.85
50	334-00 North Fork	1,094	60.00	-75.00	3.39	R2.5	29.50

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 2015/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	334-00 Oak Grove	3,253	60.00	-30.00	3.08	R2.5	32.47
13	334-00 Pelton	2,527	60.00	-75.00	3.09	R2.5	32.36
14	334-00 River Mill	2,613	60.00	-45.00	3.05	R2.5	32.79
15	334-00 Round Butte	2,312	60.00	-35.00	2.98	R2.5	33.56
16	334-00 Sullivan	4,288	60.00	-25.00	4.74	R2.5	21.10
17	335-00 Faraday	228	55.00	-15.00	4.28	R0.5	23.36
18	335-00 North Fork	495	55.00	-50.00	3.88	R0.5	25.77
19	335-00 Oak Grove	260	55.00	-5.00	3.85	R0.5	25.97
20	335-00 OG Timothy Lake	35	55.00	-5.00	4.18	R0.5	23.92
21	335-00 Pelton	181	55.00	-40.00	4.43	R0.5	22.57
22	335-00 River Mill	15	55.00	-30.00	3.64	R0.5	27.47
23	335-00 Round Butte	776	55.00	-30.00	3.97	R0.5	25.19
24	335-00 Sullivan	109	55.00	-25.00	5.44	R0.5	18.38
25	336-00 Faraday	1,976	80.00	-15.00	2.93	R1.5	34.13
26	336-00 North Fork	2,580	80.00	-50.00	3.12	R1.5	32.05
27	336-00 Oak Grove	2,215	80.00	-5.00	3.08	R1.5	32.47
28	336-00 OG Timothy Lake	107	80.00	-5.00	2.99	R1.5	33.44
29	336-00 Pelton	2,148	80.00	-40.00	2.94	R1.5	34.01
30	336-00 River Mill	458	80.00	-30.00	2.93	R1.5	34.13
31	336-00 Round Butte	1,576	80.00	-30.00	3.18	R1.5	31.45
32	337-00 Hydro ARO	5				SQ	
33	SUBTOTAL HYDRO	481,092					
34	341-00 Beaver	35,595	70.00	-8.00	6.11	R2	16.37
35	341-00 Biglow	32,893	40.00	-9.00	2.94	R4	34.01
36	341-00 Coyote Springs	11,227	70.00	-8.00	4.02	R2	24.88
37	341-00 Port Westward	41,368	70.00	-10.00	3.09	R2	32.36
38	341-00 Port Westward 2	28,893	70.00	-7.00	2.36	R2	42.37
39	341-00 Tucannon	17,770	40.00	-12.00	2.52	R4	39.68
40	342-00 Beaver	51,148	50.00	-8.00	6.70	R3	14.93
41	342-00 Beaver 8	1	50.00	-8.00	5.94	R3	16.84
42	342-00 Coyote Springs	36,852	50.00	-8.00	4.22	R3	23.70
43	342-00 KB Pipeline	20,299	50.00	-8.00	6.14	R3	16.29
44	342-00 Port Westward	9,475	50.00	-10.00	3.08	R3	32.47
45	342-00 Port Westward 2	6,601	50.00	-7.00	2.40	R3	41.67
46	344-00 Beaver	101,421	45.00	-8.00	6.72	R1	14.88
47	344-00 Beaver 8	3,831	45.00	-8.00	6.61	R1	15.13
48	344-00 Biglow	860,740	30.00	-9.00	4.34	R3	23.04
49	344-00 Coyote Springs	124,431	45.00	-8.00	5.06	R1	19.76
50	344-00 Port Westward	193,349	45.00	-10.00	4.10	R1	24.39

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	344-00 Port Westward 2	241,968	45.00	-7.00	2.74	R1	36.50
13	344-00 Sunway 1	224	25.00	-2.00	5.82	S2.5	17.18
14	344-00 Sunway 2	1,286	25.00	-2.00	7.07	S2.5	14.14
15	344-00 Tucannon	446,379	30.00	-12.00	3.34	R3	29.94
16	345-00 Beaver	24,028	40.00	-6.00	7.35	R2.5	13.61
17	345-00 Beaver 8	117	40.00	-6.00	6.17	R2.5	16.21
18	345-00 Biglow	25,496	30.00	-6.00	4.51	R2.5	22.17
19	345-00 Coyote Springs	12,133	40.00	-6.00	5.05	R2.5	19.80
20	345-00 Dispatch Gen	11,479	40.00	-6.00	3.51	R2.5	28.49
21	345-00 Port Westward	8,949	40.00	-6.00	3.69	R2.5	27.10
22	345-00 Port Westward 2	9,474	40.00	-6.00	2.68	R2.5	37.31
23	345-00 Tucannon	15,801	30.00	-6.00	3.34	R2.5	29.94
24	346-00 Beaver	4,278	55.00	-2.00	6.33	R2	15.80
25	346-00 Biglow	1,324	35.00	-2.00	3.97	R2.5	25.19
26	346-00 Coyote Springs	2,625	55.00	-2.00	4.26	R2	23.47
27	346-00 KB Pipeline	82	55.00	-2.00	6.28	R2	15.92
28	346-00 Port Westward	3,250	55.00	-2.00	3.32	R2	30.12
29	346-00 Port Westward 2	3,137	55.00	-2.00	2.45	R2	40.82
30	346-00 Tucannon	486	35.00	-2.00	2.88	R2.5	34.72
31	347-00 Beaver ARO	1,800				SQ	
32	347-00 Biglow ARO	1,837				SQ	
33	347-00 Carty ARO	2,965				SQ	
34	347-00 Port West ARO	231				SQ	
35	347-00 Port West 2 ARO	647				SQ	
36	347-00 Tucannon ARO	6,372				SQ	
37	SUBTOTAL OTHER	2,402,262					
38	352-00 Struct & Impr	19,313	60.00	-15.00	2.68	R2.5	37.31
39	353-00 Sta Equip Oth	267,904	55.00	-15.00	2.89	R2	34.60
40	353-00 Boardman	7,871	55.00	-10.00	19.67	Life Span - 2020	5.08
41	354-00 Towers - Other	48,744	70.00	-10.00	2.89	R3	34.60
42	355-00 Poles - Other	25,714	50.00	-50.00	3.15	R1.5	31.75
43	356-00 Ovhd Wire - Oth	74,757	60.00	-30.00	2.39	R2.5	41.84
44	359-00 Roads & Trails	286	60.00		3.46	R4	28.90
45	359-10 Trans ARO	34				SQ	
46	SUBTOTAL TRANS	444,623					
47	361-00 Struct & Impr	39,801	70.00	-25.00	2.36	R1.5	42.37
48	362-00 Sta Equp - Oth	472,306	54.00	-20.00	3.28	S0	30.49
49	363-00 Stor Battery	387	15.00	-5.00	7.70	L3	12.99
50	364-00 Poles, Towers	349,610	48.00	-60.00	3.58	R1	27.93

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 2015/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	365-00 Overhead Wire	587,352	48.00	-70.00	3.45	S0.5	28.99
13	366-00 Undrgrd Conduit	15,385	75.00	-13.00	2.20	R4	45.45
14	367-00 Undrgrd Wire	690,312	50.00	-70.00	3.09	S1.5	32.36
15	368-00 Line Transformr	357,878	45.00	-20.00	3.55	R3	28.17
16	369-01 Services Ovrhd	61,277	55.00	-45.00	3.18	R1.5	31.45
17	369-03 Services Undrgd	354,794	50.00	-45.00	2.78	R4	35.97
18	370-00 Meters Other	1,612	30.00	-8.00	5.21	S1.5	19.19
19	370-01 AMI Meters	140,478	16.00	-8.00	8.28	S2.5	12.08
20	370-02 Retained Meters	7,317	16.00	-8.00	13.68	L0.5	7.31
21	371-00 Eq on Cust Prem	376	30.00		5.94	R4	16.84
22	373-01 Circuits	21,917	46.00	-30.00	3.64	S0.5	27.47
23	373-02 Fixtures	52,561	28.00	-30.00	6.25	L1	16.00
24	373-07 Sentinel Lights	8,491	29.00	-30.00	6.28	L0.5	15.92
25	374-00 Dist ARO	477				SQ	
26	SUBTOTAL DIST	3,162,331					
27	390-00 Struct - Other	89,085	40.00	-5.00	4.85	R0.5	20.62
28	390-00 World Trade Ctr	23,451			3.25	SQ	30.77
29	390-01 Equipment	3,970	40.00	-5.00	4.85	R0.5	20.62
30	390-02 Land Improvmnt	1,871	40.00	-5.00	4.85	R0.5	20.62
31	390-03 Info Systems	1,085	40.00	-5.00	4.85	R0.5	20.62
32	391-00 Off Furn - Oth	22,194	15.00		16.03	SQ	6.24
33	391-00 Boardman	89	15.00		19.67	Life span - 2020	5.08
34	391-02 Computers - Oth	87,812	5.00		36.17	SQ	2.76
35	391-02 Boardman	268	5.00		19.67	Life span - 2020	5.08
36	392-04 Hvy Duty Trucks	15,434	19.00	10.00	7.09	S2	14.10
37	392-04 Boardman	681	19.00	10.00	19.67	Life span - 2020	5.08
38	392-05 Med Duty Trucks	14,478	15.00	10.00	11.65	S1.5	8.58
39	392-05 Boardman	337	15.00	10.00	19.67	Life span - 2020	5.08
40	392-06 Lgt Duty Trucks	10,782	12.00	10.00	16.67	L2	6.00
41	392-06 Boardman	368	12.00	10.00	19.67	Life span - 2020	5.08
42	392-08 Trailers	6,137	25.00	10.00	7.07	S0	14.14
43	392-08 Boardman	32	25.00	10.00	19.67	Life span - 2020	5.08
44	392-09 Automobiles	1,225	11.00	10.00	16.85	S1.5	5.93
45	392-09 Boardman	12	11.00	10.00	19.67	Life span - 2020	5.08
46	392-10 Helicopter	2,703	20.00	10.00	6.57	S4	15.22
47	393-00 Stores Equip	476	20.00		8.67	SQ	11.53
48	393-01 Forklifts	2,266	20.00		8.67	SQ	11.53
49	393-01 Boardman	88	20.00		19.67	Life span - 2020	5.08
50	394-00 Tool & Shop Eq	15,007	20.00		12.15	SQ	8.23

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	394-00 Boardman	404	20.00		19.67	Life span - 2020	5.08
13	395-00 Lab Equipment	8,976	17.00		12.81	SQ	7.81
14	395-00 Boardman	270	17.00		19.67	Life span - 2020	5.08
15	396-01 Man Lift Equip	25,701	14.00	5.00	13.07	S1.5	7.65
16	396-02 Digger Equip	6,299	15.00	5.00	9.63	S3	10.38
17	396-02 Boardman	810	15.00	5.00	19.67	Life span 2020	5.08
18	396-03 Crane	4,413	20.00	5.00	7.41	L3	13.50
19	396-03 Boardman	288	20.00	5.00	19.67	Life span - 2020	5.08
20	396-07 Construct Equ	6,266	20.00	5.00	9.12	L1	10.96
21	396-07 Boardman	1,120	20.00	5.00	19.67	Life span - 2020	5.08
22	397-01 Line Equip	6,771	15.00		9.03	SQ	11.07
23	397-03 Radio Equip	90,221	15.00		15.62	SQ	6.40
24	397-03 Boardman	453	15.00		19.67	Life span - 2020	5.08
25	397-06 Mobile Radio	347	15.00		8.64	SQ	11.57
26	397-06 Boardman	7	15.00		19.67	Life span - 2020	5.08
27	397-07 Telephone Equip	847	15.00		19.84	SQ	5.04
28	397-07 Boardman	1	15.00		19.67	Life span - 2020	5.08
29	398-00	308	15.00		6.37	SQ	15.70
30	399-10 General ARO	65				SQ	
31	SUBTOTAL GEN PLANT	453,418					
32							
33	Plant balance are						
34	YE 2015 original cost						
35							
36	Applied depreciation						
37	rates for all assets						
38	effective 1/1/2015 per						
39	Order 14-297 in OPUC						
40	Docket UM-1679						
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

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 2015/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		112,955	112,955	
2	Docket No. RM06-16				
3					
4	FERC-NERC Reliability		218,051	218,051	
5	Docket No. RM06-22				
6					
7	FERC-Compliant concerning Portland General		277,960	277,960	
8	Electric obligation to integarte with and				
9	purchase from PaTu Wind Farm				
10	Docket No.15-1237				
11					
12	OPUC-2016 General Rate Case		398,969	398,969	
13	Docket No. UE 294				
14					
15	OPUC-Compliant of PaTu Wind Farm LLC. against		78,180	78,180	
16	Portland General Eelctric Company, Pursuant				
17	ORS 756.500				
18	Docket No. UM 1566				
19					
20	OPUC-Investigation of Generic Power Cost to		57,200	57,200	
21	comply with the Renewable Portfolio Standard				
22	Docket No. UM 1662				
23					
24	OPUC matters less than $25,000		195,768	195,768	
25					
26	FERC matters less than $25,000		4,033	4,033	
27					
28	Non Docs matters		270,421	270,421	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL		1,613,537	1,613,537	

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	112,955					1
							2
							3
	928	218,051					4
							5
							6
	928	277,960					7
							8
							9
							10
							11
	928	398,969					12
							13
							14
	928	78,180					15
							16
							17
							18
							19
	928	57,200					20
							21
							22
							23
	928	195,768					24
							25
	928	4,033					26
							27
	928	270,421					28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		1,613,537					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 2015/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)	Internal 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	A(5)	Electric R, D & D Performed Internally - Environment
9	A(6)	Electric R, D & D Performed Internally - Other
10	B(1)	Electric R, D & D Performed Externally
11		Research Support to the Electrical Research Council or EPRI
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27	Totals	
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
5,000		930.2	5,000		3
					4
457,929		930.2	457,929		5
100,000		930.2	100,000		6
395,706		930.2	395,706		7
50,000		930.2	50,000		8
90,000		930.2	90,000		9
	184,411	930.2	184,411		10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
1,098,635	184,411		1,283,046		27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Schedule Page: 352 Line No.: 9 Column: c

Includes two projects in 2016: 1. Electric Vehicle Behavioral Assessment; 2. Capacity Value of Energy Efficiency - Oregon BEST.

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 2015/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	27,175,839		
4	Transmission	3,757,162		
5	Regional Market			
6	Distribution	17,088,881		
7	Customer Accounts	24,901,603		
8	Customer Service and Informational	6,804,621		
9	Sales			
10	Administrative and General	35,478,413		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	115,206,519		
12	Maintenance			
13	Production	11,994,713		
14	Transmission	1,150,147		
15	Regional Market			
16	Distribution	24,387,077		
17	Administrative and General	783,182		
18	TOTAL Maintenance (Total of lines 13 thru 17)	38,315,119		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	39,170,552		
21	Transmission (Enter Total of lines 4 and 14)	4,907,309		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	41,475,958		
24	Customer Accounts (Transcribe from line 7)	24,901,603		
25	Customer Service and Informational (Transcribe from line 8)	6,804,621		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	36,261,595		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	153,521,638	17,206,918	170,728,556
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)	153,521,638	17,206,918	170,728,556
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	70,545,090	3,856,105	74,401,195
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	70,545,090	3,856,105	74,401,195
72	Plant Removal (By Utility Departments)			
73	Electric Plant	774,510	41,576	816,086
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	774,510	41,576	816,086
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	1,669,722	143,321	1,813,043
79	Co-Owner Shares of Generating Facilities	4,661,034	155,958	4,816,992
80	Other	842,067	3,807,457	4,649,524
81	Payroll Allocated	25,211,335	-25,211,335	
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	32,384,158	-21,104,599	11,279,559
96	TOTAL SALARIES AND WAGES	257,225,396		257,225,396

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 2015/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 2015/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)	268,685	1,412,509	324,572	2,176,938
3	Net Sales (Account 447)	10,208,481	8,522,974	8,350,843	36,147,145
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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	10,477,166	9,935,483	8,675,415	38,324,083

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 2015/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	49,462	MW	21,300,142	7,464,472	Various	155,564
2	Reactive Supply and Voltage				3,265,563	Various	104,997
3	Regulation and Frequency Response				3,265,563	Various	244,504
4	Energy Imbalance	26,342	MWh	1,041,740	23,685	MWh	859,679
5	Operating Reserve - Spinning				3,265,563	MWh	276,771
6	Operating Reserve - Supplement				3,265,563	MWh	276,771
7	Other						
8	Total (Lines 1 thru 7)	75,804		22,341,882	20,550,409		1,918,286

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

Scheduling, System Control and Dispatch	**No of Units**	**Amount**
MW Day	27,473	1,268
MW Hour	218,642	4,972
MW Month	176	2,286
MW Week	1,750	1,368
MW Year	3,951,044	113,017
Sum of Peak Demand (KW)	3,265,387	32,653
	7,464,472	**155,564**

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

Reactive Supply and Voltage	**No of Units**	**Amount**
MW Day	-	-
MW Hour	-	8
MW Month	176	7,027
Sum of Peak Demand (KW)	3,265,387	97,962
	3,265,563	**104,997**

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

Regulation and Frequency Response	**No of Units**	**Amount**
MW Month	176	15,927
Sum of Peak Demand (KW)	3,265,387	228,577
	3,265,563	**244,504**

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.: 5 Column: g

Operating Reserve - Spinning	**No of Units**	**Amount**
MW Month	3,265,563	$276,771

Schedule Page: 398 Line No.: 6 Column: g

Operating Reserve - Supplement	**No of Units**	**Amount**
MW Month	3,265,563	$276,771

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 2015/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: PGE

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,230	2	1900	2,872	205	1,500		4,227	15
2	February	4,117	3	1900	2,676	222	1,500		4,227	
3	March	4,006	5	800	2,716	221	1,500		4,227	
4	Total for Quarter 1				8,264	648	4,500		12,681	15
5	April	3,927	13	2000	2,537	202	1,500		4,227	1
6	May	3,805	29	1600	2,640	245	1,500		4,227	
7	June	4,982	29	1800	3,306	262	1,500		4,404	75
8	Total for Quarter 2				8,483	709	4,500		12,858	76
9	July	4,929	6	1900	3,407	255	1,500		4,352	280
10	August	4,715	19	1800	3,508	262	1,500		4,404	250
11	September	4,364	12	1800	2,859	227	1,500		4,227	99
12	Total for Quarter 3				9,774	744	4,500		12,983	629
13	October	3,812	26	2000	2,631	224	1,500		4,227	223
14	November	4,344	30	800	3,314	205	1,500		4,227	535
15	December	4,584	15	2000	3,167	196	1,500		4,227	240
16	Total for Quarter 4				9,112	625	4,500		12,681	998
17	Total Year to Date/Year				35,633	2,726	18,000		51,203	1,718

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 2015/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	1500			307			
2	February	290	7	2000			307			
3	March	287	8	800			307			
4	Total for Quarter 1						921			
5	April	286	27	100			307			
6	May	262	29	2000			307			
7	June	250	1	300			307			
8	Total for Quarter 2						921			
9	July	286	31	2200			307			
10	August	290	22	600			307			
11	September	287	7	1300			307			
12	Total for Quarter 3						921			
13	October	290	11	1100			307			
14	November	289	6	600			307			
15	December	293	9	900			307			
16	Total for Quarter 4						921			
17	Total Year to Date/Year						3,684			

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

Long Term Firm Point-to-Point Reservations: Q1

Reservation #	Customer	MW Granted Jan 2015	MW Granted Feb 2015	MW Granted Mar 2015	Earliest Termination Date
432190	Portland General Electric Company	100	100	100	1/1/2022
71472976	Shell Energy North America (US) LP	200	200	200	1/1/2022
71915367	Powerex Inc.	97	97	97	1/1/2017
74382640	Portland General Electric Company	100	100	100	7/1/2017
74566698	Portland General Electric Company	100	100	100	1/1/2022
75731986	Puget Sound Energy Marketing	100	100	100	1/1/2017
76073144	Portland General Electric Company	(14)	(14)	(14)	7/1/2017
76412778	Portland General Electric Company	200	200	200	1/1/2017
77316434	Avista Corp	100	100	100	1/1/2023
77594664	Powerex Inc.	165	165	165	6/1/2018
79072075	Powerex Inc.	10	10	10	1/1/2034
79082732	Portland General Electric Company	10	10	10	1/1/2034
79084421	Exelon Generation Company, LLC	10	10	10	1/1/2034
79091330	Rainbow Energy Mktg Corp. (redirected MW)	10	10	10	1/1/2034
79091530	Morgan Stanley Capital Group	10	10	10	1/1/2034
79091653	Public Utility District No. 1 of Klickitat County	11	11	11	1/1/2034
79091680	The Energy Authority, Inc.	10	10	10	1/1/2034
79092316	Public Utility District No. 1 of Lewis County	11	11	11	1/1/2034
79092388	Public Utility District No. 1 of Franklin County	10	10	10	1/1/2034
79092678	Public Utility District No. 1 of Cowlitz County	10	10	10	1/1/2034
79875117	Portland General Electric Company	250	250	250	1/1/2020
		1,500	**1,500**	**1,500**	

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 2015	MW Granted Feb 2015	MW Granted Mar 2015
80608493	Portland General Electric Company	500	-	-
80608542	Portland General Electric Company	200	-	-
80608559	Portland General Electric Company	2	-	-
80609407	Portland General Electric Company	3,300	-	-
80623079	Portland General Electric Company	25	-	-
80623111	Portland General Electric Company	200	-	-
80697746	Portland General Electric Company	-	25	25
80697770	Portland General Electric Company	-	200	200
80697777	Portland General Electric Company	-	500	500
80697785	Portland General Electric Company	-	200	200
80697790	Portland General Electric Company	-	2	2
80741701	Portland General Electric Company	-	3,300	-
80833605	Portland General Electric Company	-	-	3,300
	Total	**4,227**	**4,227**	**4,227**

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

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 2015	MW Granted May 2015	MW Granted Jun 2015	Earliest Termination Date
432190	Portland General Electric Company	100	100	100	1/1/2022
71472976	Shell Energy North America (US) LP	200	200	200	1/1/2022
71915367	Powerex Inc.	97	97	97	1/1/2017
74382640	Portland General Electric Company	100	100	100	7/1/2017
74566698	Portland General Electric Company	100	100	100	1/1/2022
75731986	Puget Sound Energy Marketing	100	100	100	1/1/2017
76073144	Portland General Electric Company	(14)	(14)	(14)	7/1/2017
76412778	Portland General Electric Company	200	200	200	1/1/2017
77316434	Avista Corp	100	100	100	1/1/2023
77594664	Powerex Inc.	165	165	165	6/1/2018
79072075	Powerex Inc.	10	10	10	1/1/2034
79082732	Portland General Electric Company	10	10	10	1/1/2034
79084421	Exelon Generation Company, LLC	10	10	10	1/1/2034
79091330	Rainbow Energy Mktg Corp. (redirected MW)	10	10	10	1/1/2034
79091530	Morgan Stanley Capital Group	10	10	10	1/1/2034
79091653	Public Utility District No. 1 of Klickitat County	11	11	11	1/1/2034
79091680	The Energy Authority, Inc.	10	10	10	1/1/2034
79092316	Public Utility District No. 1 of Lewis County	11	11	11	1/1/2034
79092388	Public Utility District No. 1 of Franklin County	10	10	10	1/1/2034
79092678	Public Utility District No. 1 of Cowlitz County	10	10	10	1/1/2034
79875117	Portland General Electric Company	250	250	250	1/1/2020
		1,500	**1,500**	**1,500**	

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 2015	MW Granted May 2015	MW Granted Jun 2015
80697746	Portland General Electric Company	25	25	25
80697770	Portland General Electric Company	200	200	200
80697777	Portland General Electric Company	500	500	500
80697785	Portland General Electric Company	200	200	200
80697790	Portland General Electric Company	2	2	2
80970015	Portland General Electric Company	3,300	-	-
81110624	Portland General Electric Company	-	3,300	-
81227840	Portland General Electric Company	-	-	3,300
81334361	Macquarie Energy LLC	-	-	50
81334542	Macquarie Energy LLC	-	-	50
81334878	Puget Sound Energy Marketing	-	-	77
	Total	**4,227**	**4,227**	**4,404**

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

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 2015	MW Granted Aug 2015	MW Granted Sep 2015	Earliest Termination Date
71472976	Shell Energy North America (US) LP	200	200	200	1/1/2022
432190	Portland General Electric Company	100	100	100	1/1/2022
71915367	Powerex Inc.	97	97	97	1/1/2017
74382640	Portland General Electric Company	100	100	100	7/1/2017
74566698	Portland General Electric Company	100	100	100	1/1/2022
75731986	Puget Sound Energy Marketing	100	100	100	1/1/2017
76073144	Portland General Electric Company	(14)	(14)	(14)	7/1/2017
76412778	Portland General Electric Company	200	200	200	1/1/2017
77316434	Avista Corp	100	100	100	1/1/2023
77594664	Powerex Inc.	165	165	165	6/1/2018
79072075	Powerex Inc.	10	10	10	1/1/2034
79082732	Portland General Electric Company	10	10	10	1/1/2034
79084421	Exelon Generation Company, LLC	10	10	10	1/1/2034
79091330	Rainbow Energy Mktg Corp. (redirected MW)	10	10	10	1/1/2034
79091530	Morgan Stanley Capital Group	10	10	10	1/1/2034
79091653	Public Utility District No. 1 of Klickitat County	11	11	11	1/1/2034
79091680	The Energy Authority	10	10	10	1/1/2034
79092316	Public Utility District No. 1 of Lewis County	11	11	11	1/1/2034
79092388	Public Utility District No. 1 of Franklin County	10	10	10	1/1/2034
79092678	Public Utility District No. 1 of Cowlitz County	10	10	10	1/1/2034
79875117	Portland General Electric Company	250	250	250	1/1/2020
		1,500	**1,500**	**1,500**	

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 2015	MW Granted Aug 2015	MW Granted Sep 2015
80697746	Portland General Electric Company	25	25	25
80697770	Portland General Electric Company	200	200	200
80697777	Portland General Electric Company	500	500	500
80697785	Portland General Electric Company	200	200	200
80697790	Portland General Electric Company	2	2	2
81334492	Portland General Electric Company	3,300	-	-
81369880	Macquarie Energy LLC	125	-	-
81459579	Portland General Electric Company	-	3,300	-
81556015	Macquarie Energy LLC	-	50	-
81560102	Puget Sound Energy Marketing	-	100	-
81560117	Puget Sound Energy Marketing	-	27	-
81587633	Portland General Electric Company	-		3,300
	Total	**4,352**	**4,404**	**4,227**

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

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 2015	MW Granted Nov 2015	MW Granted Dec 2015	Earliest Termination Date
71472976	Shell Energy North America (US) LP	200	200	200	1/1/2022
432190	Portland General Electric Company	100	100	100	1/1/2022
71915367	Powerex Inc.	97	97	97	1/1/2017
74382640	Portland General Electric Company	100	100	100	7/1/2017
74566698	Portland General Electric Company	100	100	100	1/1/2022
75731986	Puget Sound Energy Marketing	100	100	100	1/1/2017
76073144	Portland General Electric Company	(14)	(14)	(14)	7/1/2017
76412778	Portland General Electric Company	200	200	200	1/1/2017
77316434	Avista Corp	100	100	100	1/1/2023
77594664	Powerex Inc.	165	165	165	6/1/2018
79072075	Powerex Inc.	10	10	10	1/1/2034
79082732	Portland General Electric Company	10	10	10	1/1/2034
79084421	Exelon Generation Company, LLC	10	10	10	1/1/2034
79091330	Rainbow Energy Mktg Corp. (redirected MW)	10	10	10	1/1/2034
79091530	Morgan Stanley Capital Group	10	10	10	1/1/2034
79091653	Public Utility District No. 1 of Klickitat County	11	11	11	1/1/2034
79091680	The Energy Authority	10	10	10	1/1/2034
79092316	Public Utility District No. 1 of Lewis County	11	11	11	1/1/2034
79092388	Public Utility District No. 1 of Franklin County	10	10	10	1/1/2034
79092678	Public Utility District No. 1 of Cowlitz County	10	10	10	1/1/2034
79875117	Portland General Electric Company	250	250	250	1/1/2020
		1,500	**1,500**	**1,500**	

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 2015	MW Granted Nov 2015	MW Granted Dec 2015
80697746	Portland General Electric Company	25	25	25
80697770	Portland General Electric Company	200	200	200
80697777	Portland General Electric Company	500	500	500
80697785	Portland General Electric Company	200	200	200
80697790	Portland General Electric Company	2	2	2
81712307	Portland General Electric Company	3,300		
81796154	Portland General Electric Company		3,300	
81917898	Portland General Electric Company			3,300
	Total	**4,227**	**4,227**	**4,227**

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

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

These entries are the "Transmission Provider's Monthly Transmission System Peak" as defined in PGE's OATT in Section 1.47, the maximum firm usage of PGE's 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 2015	MW Granted Feb 2015	MW Granted Mar 2015	Earliest Termination Date
76059414	Portland General Electric Company	307	307	307	7/1/2022

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

These entries are the "Transmission Provider's Monthly Transmission System Peak" as defined in PGE's OATT in Section 1.47, the maximum firm usage of PGE's 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 2015	MW Granted May 2015	MW Granted Jun 2015	Earliest Termination Date
76059414	Portland General Electric Company	307	307	307	7/1/2022

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

These entries are the "Transmission Provider's Monthly Transmission System Peak" as defined in PGE's OATT in Section 1.47, the maximum firm usage of PGE's 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 2015	MW Granted Aug 2015	MW Granted Sep 2015	Earliest Termination Date
76059414	Portland General Electric Company	307	307	307	7/1/2022

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

These entries are the "Transmission Provider's Monthly Transmission System Peak" as defined in PGE's OATT in Section 1.47, the maximum firm usage of PGE's 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 2015	MW Granted Nov 2015	MW Granted Dec 2015	Earliest Termination Date
76059414	Portland General Electric Company	307	307	307	7/1/2022

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 2015/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 2015/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	4,128,138
4	Nuclear	
5	Hydro-Conventional	1,452,839
6	Hydro-Pumped Storage	
7	Other	6,571,039
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	12,152,016
10	Purchases	9,841,229
11	Power Exchanges:	
12	Received	440,265
13	Delivered	439,113
14	Net Exchanges (Line 12 minus line 13)	1,152
15	Transmission For Other (Wheeling)	
16	Received	6,589,962
17	Delivered	6,532,762
18	Net Transmission for Other (Line 16 minus line 17)	57,200
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	22,051,597

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	17,696,386
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,162,844
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	26,245
27	Total Energy Losses	1,166,122
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	22,051,597

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 2015/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	1,916,409	207,421	3,153	2	18
30	February	1,652,139	209,569	2,967	24	8
31	March	1,719,388	214,257	2,973	4	8
32	April	1,669,386	218,779	2,812	15	8
33	May	1,680,557	240,047	2,908	29	17
34	June	1,811,181	231,421	3,610	30	18
35	July	2,131,795	401,001	3,914	30	18
36	August	2,079,558	434,783	3,770	19	18
37	September	1,797,485	369,260	3,293	11	18
38	October	1,711,959	238,880	2,700	5	20
39	November	1,802,484	190,002	3,401	30	18
40	December	2,022,056	256,056	3,255	31	18
41	TOTAL	21,994,397	3,211,476			

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

In addition to the generation from the Beaver, Port Westward 1, Port Westward 2, and Coyote Springs generation plants, as shown on page 403, Other Generation includes 1,788,423 megawatt hours of net wind energy scheduled and delivered by Bonneville Power Administration (BPA) from PGE's Biglow Canyon Wind Farm and Tucannon River Wind Farm. Actual net wind generation from the two projects to BPA was 1,795,164 megawatt hours.

The Biglow Canyon Wind Farm was placed in service in three phases between December 2007 and August 2010. Key statistics include the following:

In-service production cost at 12/31/2015:	$922,289,208
Total installed capacity:	450 megawatts
Operations and maintenance expenses for 2015:	$19,588,851

The Tucannon River Wind Farm was placed in service on December 15, 2014. Key statistics include the following:

In-service production cost at 12/31/2015:	$486,808,225
Total installed capacity:	267 megawatts
Operations and maintenance expenses for 2015:	$9,230,784

Schedule Page: 401 Line No.: 27 Column: b

PGE has ownership in a 5MW storage battery (Salem Smart Power Center) with a Plant in service balance of $384,933 as of year end 2015, recorded to FERC 363 - Storage Battery Equipment, Distribution. This battery is located in the Salem, Oregon area and is connected to PGE's Oxford Substation. PGE recorded expenses for 2015 to FERC 584.1 - Operation of Energy Storage Equipment $3,784 and FERC 592.2 - Maintenance of Energy Storage Equipment $7,290. Line loss includes 0.4 MWh of Energy stored in this battery at year end.

Schedule Page: 401 Line No.: 40 Column: c

Line Losses associated with Sales for Resale have been estimated. This note applies to column (c), lines 29 - 40.

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 (PGE Share)* (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	577.90
6	Net Peak Demand on Plant - MW (60 minutes)	599	0
7	Plant Hours Connected to Load	4993	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	119	0
12	Net Generation, Exclusive of Plant Use - KWh	2350188000	1930128000
13	Cost of Plant: Land and Land Rights	939463	832853
14	Structures and Improvements	153328063	140836047
15	Equipment Costs	575882623	512269325
16	Asset Retirement Costs	52066451	47635020
17	Total Cost	782216600	701573245
18	Cost per KW of Installed Capacity (line 17/5) Including	1218.0265	1214.0046
19	Production Expenses: Oper, Supv, & Engr	2885072	2487667
20	Fuel	62999916	58262844
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	5737718	4965984
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	6741084	6347322
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	748164	735324
30	Maintenance of Structures	704930	617290
31	Maintenance of Boiler (or reactor) Plant	1688797	1465292
32	Maintenance of Electric Plant	16887198	14919553
33	Maintenance of Misc Steam (or Nuclear) Plant	442088	395188
34	Total Production Expenses	98834967	90196464
35	Expenses per Net KWh	0.0421	0.0467

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	1400657	10828	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	41.597	76.796	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	44.979	105.957	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.641	18.190	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.027	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10151.900	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 2015/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			2198010000		
13	Cost of Plant: Land and Land Rights	0			3328952		
14	Structures and Improvements	0			114980317		
15	Equipment Costs	0			332422923		
16	Asset Retirement Costs	0			16635323		
17	Total Cost	0			467367515		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			1501.8236		
19	Production Expenses: Oper, Supv, & Engr	0			336614		
20	Fuel	0			33592925		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			2054803		
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			2058906		
27	Rents	0			40272		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			510413		
30	Maintenance of Structures	0			848884		
31	Maintenance of Boiler (or reactor) Plant	0			4282556		
32	Maintenance of Electric Plant	0			447779		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			575581		
34	Total Production Expenses	0			44748733		
35	Expenses per Net KWh	0.0000			0.0204		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

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

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

Plant Name: *Beaver* (d)			Plant Name: *Port Westward 1* (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
610.90			483.30			271.20			5
523			432			267			6
2463			6184			4785			7
0			0			0			8
533			421			270			9
0			0			0			10
50			24			30			11
443827000			2316566000			1680017000			12
0			0			0			13
35501208			41462662			11227472			14
195036518			225237143			176041995			15
1686492			231072			113193			16
232224218			266930877			187382660			17
380.1346			552.3089			690.9390			18
509820			719155			1145600			19
18817071			93197581			54446138			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
2398542			2399118			1276424			25
2852284			1313571			790862			26
218813			39422			75468			27
0			0			0			28
724366			14272			32865			29
264131			45394			115005			30
0			0			0			31
7688253			8713260			5795531			32
242707			59054			23279			33
33715987			106500827			63701172			34
0.0760			0.0460			0.0379			35
Gas	Oil		Gas	Oil		Gas	Oil		36
Mcf's	Barrels		Mcf's	Barrels		Mcf's	Barrels		37
4333861	588	0	16028472	0	0	12489793	0	0	38
1019000	138690	0	1019000	138690	0	1019000	138690	0	39
1.862	0.000	0.000	2.396	0.000	0.000	2.241	0.000	0.000	40
3.162	156.883	0.000	3.215	0.000	0.000	2.809	0.000	0.000	41
3.102	26.984	0.000	3.154	0.000	0.000	2.756	0.000	0.000	42
0.031	0.000	0.000	0.022	0.000	0.000	0.021	0.000	0.000	43
9955.200	0.000	0.000	7045.800	0.000	0.000	7569.600	0.000	0.000	44

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: *Port Westward 2* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Reciprocating Engine			1
Outdoor			2
2014			3
2014			4
225.00	0.00	0.00	5
225	0	0	6
3367	0	0	7
0	0	0	8
225	0	0	9
0	0	0	10
0	0	0	11
342205000	0	0	12
0	0	0	13
28892515	0	0	14
261179640	0	0	15
647461	0	0	16
290719616	0	0	17
1292.0872	0	0	18
58165	0	0	19
10641484	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
469545	0	0	25
776982	0	0	26
6698	0	0	27
0	0	0	28
3831	0	0	29
5065	0	0	30
0	0	0	31
1325466	0	0	32
39351	0	0	33
13326587	0	0	34
0.0389	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
Gas	Oil								36
MCf's	Barrels								37
3002172	0	0	0	0	0	0	0	0	38
1019000	138690	0	0	0	0	0	0	0	39
2.274	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
3.335	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
3.272	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
8691.300	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 (90% interest) and operator of the Boardman Plant. The other owner is Idaho Power Company (10%). Reported here are 100% costs and plant statistics, including shared and non-shared costs.

In 1985, PGE sold a 15% undivided interest in the Boardman Plant and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under the terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. This transaction was approved by the FERC on December 19, 2013 through Docket EC14-13-000.

The original cost of the 15% of the Boardman Plant and the 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line at December 31, 2013 was estimated at $96 million and $2 million, respectively. It was also estimated that these assets were fully depreciated at the time the acquisition was executed since it coincided with the expiration of various agreements under the terms of the original 1985 transaction.

The proposed final accounting entries associated with this transaction were submitted to the FERC on June 27, 2014, in compliance with the accounting under the Uniform System of Accounts (Docket AC14-129-000). On September 29, 2014, FERC approved the final proposed journal entries. In September 2014, the final accounting entries were executed, which increased both Electric plant in service (Account 101) and Accumulated provision for depreciation (Account 108) by $97,861,971 (Steam $94,061,144 and Transmission $3,800,827) with corresponding offsets to Electric plant purchased or sold (Account 102).

In December 2014 PGE acquired an additional 10% undivided interest from another co-owner in the Boardman Plant, and associated equipment and facilities, as well as certain contracts and other rights related to that co-owner's ownership interest in the Boardman Plant.

The original cost of the 10% share of the assets acquired at December 31, 2014 was estimated at $67 million.

On September 19, 2014, PGE filed an application requesting authorization for the acquisition of the rights, titles, and interests associated with this transaction pursuant to section 203(a)(1) of the Federal Power Act (FPA), including proposed accounting entries. On November 14, 2014, the FERC concluded that the proposed transaction was consistent with public interest and authorized the transaction (Docket EC14-147-000). In December 2014, accounting entries were executed which increased Electric plant in service (Account 101) by $67,211,321 (Steam Plant $65,882,727 and Transmission $1,328,594), Accumulated provision for depreciation (Account 108) by $47,707,066 (Steam $46,764,020 and Transmission $943,046), and Construction work in progress (Account 107) by $372,000 with corresponding offsets to Electric plant acquisition adjustments (Account 114).

On April 20, 2015 (Docket EC14-147-000) PGE submitted proposed final journal entries for acceptance as prescribed under Electric Plant Instruction No. 5 and Account 102 Electric plant purchased or sold. Based on discussion with FERC Commission staff, PGE re-filed on May 27, 2015 (Docket AC15-110-000) clearing the negative acquisition recorded to Account 114, Electric plant acquisition adjustment immediately instead of amortizing the balance over the remaining life of the plant. On July 6, 2015 (Docket EC14-147-000) the FERC approved the proposed journal entries.

Schedule Page: 402 Line No.: -1 Column: c

Respondent is the principal owner and operator of the Boardman Plant. Installed capacity on line 5c represents 90% share. Reported here are the respondent's share of expenses incurred during the year and investment as of December 31, 2014, as appropriate. Details are reported in Page 402 col (b).

In 1985, PGE sold a 15% undivided interest in the Boardman Plant and a 10.714% undivided interest in the Company’s share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under the terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. This transaction was approved by the FERC on December 19, 2013 through Docket EC14-13-000.

The original cost of the 15% of the Boardman Plant and the 10.714% undivided interest in the Company’s share of the Pacific Northwest Intertie transmission line at December 31, 2013 was estimated at $96 million and $2 million, respectively. It was also estimated that these assets were fully depreciated at the time the acquisition was executed since it coincided with the expiration of various agreements under the terms of the original 1985 transaction.

The proposed final accounting entries associated with this transaction were submitted to the FERC on June 27, 2014, in compliance with the accounting under the Uniform System of Accounts (Docket AC14-129-000). On September 29, 2014, FERC approved the final proposed journal entries. In September 2014, the final accounting entries were executed, which increased both Electric plant in service (Account 101) and Accumulated provision for depreciation (Account 108) by $97,861,971 (Steam $94,061,144 and Transmission $3,800,827) with corresponding offsets to Electric plant purchased or sold (Account 102).

In December 2014 PGE acquired an additional 10% undivided interest from another co-owner in the Boardman Plant, and associated equipment and facilities, as well as certain contracts and other rights related to that co-owner’s ownership interest in the Boardman Plant.

The original cost of the 10% share of the assets acquired at December 31, 2014 was estimated at $67 million.

On September 19, 2014, PGE filed an application requesting authorization for the acquisition of the rights, titles, and interests associated with this transaction pursuant to section 203(a)(1) of the Federal Power Act (FPA), including proposed accounting entries. On November 14, 2014, the FERC concluded that the proposed transaction was consistent with public interest and authorized the transaction (Docket EC14-147-000). In December 2014, accounting entries were executed which increased Electric plant in service (Account 101) by $67,211,321 (Steam Plant $65,882,727 and Transmission $1,328,594), Accumulated provision for depreciation (Account 108) by $47,707,066 (Steam $46,764,020 and Transmission $943,046), and Construction work in progress (Account 107) by $372,000 with corresponding offsets to Electric plant acquisition adjustments (Account 114).

On April 20, 2015 (Docket EC14-147-000) PGE submitted proposed final journal entries for acceptance as prescribed under Electric Plant Instruction No. 5 and Account 102 Electric plant purchased or sold. Based on discussion with FERC Commission staff, PGE re-filed on May 27, 2015 (Docket AC15-110-000) clearing the negative acquisition recorded to Account 114, Electric plant acquisition adjustment immediately instead of amortizing the balance over the remaining life of the plant. On July 6, 2015 (Docket EC14-147-000) the FERC approved the proposed journal entries.

Schedule Page: 403   Line No.: 9   Column: d

Based on January average temperature.

Schedule Page: 403   Line No.: 9   Column: e

Based on January average temperature.

Schedule Page: 403   Line No.: 9   Column: f

Based on January average temperature.

Schedule Page: 402.1 Line No.: -1 Column: c

Jointly owned. PP&L Montana, LLC is the joint owner/operator of the plant. Reported herein is respondent's 20 percent share of installed capacity, cost of plant, net generation and production expenses of Units 3 & 4.

Schedule Page: 403.1 Line No.: -1 Column: d

On December 30, 2014 the Port Westward 2 Plant was declared in-service and commercially operable to PGE as of this date. The Plant uses 12 natural gas-fired reciprocating engines.

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

The Boardman coal plant does not use oil for generation. Oil is used during start up or set up conditions and other temporary operating conditions.

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

The Beaver Plant uses gas extensively for generation with minimal oil usage. The Average BTU per KWh Net Generation reported is a composite heat rate for both fuels.

Schedule Page: 402 Line No.: 44 Column: e1

The Port Westward 1 Plant uses gas extensively for generation with minimal oil usage. The Average BTU per KWh Net Generation reported is a composite heat rate for both fuels.

Schedule Page: 402 Line No.: 44 Column: f1

The Coyote Springs Plant uses gas extensively for generation with minimal oil usage. 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 2015/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	46
7	Plant Hours Connect to Load	0	8,737
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	48
12	Net Generation, Exclusive of Plant Use - Kwh	0	105,960,000
13	Cost of Plant		
14	Land and Land Rights	0	33,434
15	Structures and Improvements	0	6,507,399
16	Reservoirs, Dams, and Waterways	0	25,710,246
17	Equipment Costs	0	9,552,691
18	Roads, Railroads, and Bridges	0	1,976,298
19	Asset Retirement Costs	0	90
20	TOTAL cost (Total of 14 thru 19)	0	43,780,158
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	1,189.6782
22	Production Expenses		
23	Operation Supervision and Engineering	0	156,944
24	Water for Power	0	63,384
25	Hydraulic Expenses	0	569,960
26	Electric Expenses	0	205,516
27	Misc Hydraulic Power Generation Expenses	0	857,615
28	Rents	0	127,686
29	Maintenance Supervision and Engineering	0	238,741
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	36,420
32	Maintenance of Electric Plant	0	225,850
33	Maintenance of Misc Hydraulic Plant	0	390,585
34	Total Production Expenses (total 23 thru 33)	0	2,872,701
35	Expenses per net KWh	0.0000	0.0271

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)	107	0
7	Plant Hours Connect to Load	7,269	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	398,056,000	265,383,000
13	Cost of Plant		
14	Land and Land Rights	3,672,025	2,448,139
15	Structures and Improvements	9,119,781	6,077,817
16	Reservoirs, Dams, and Waterways	15,520,875	10,573,893
17	Equipment Costs	10,181,733	6,813,323
18	Roads, Railroads, and Bridges	3,215,120	2,148,378
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	41,709,534	28,061,550
21	Cost per KW of Installed Capacity (line 20 / 5)	379.8683	383.3545
22	Production Expenses		
23	Operation Supervision and Engineering	255,969	151,608
24	Water for Power	153,635	89,796
25	Hydraulic Expenses	2,246,682	1,522,206
26	Electric Expenses	214,091	145,717
27	Misc Hydraulic Power Generation Expenses	404,049	211,583
28	Rents	12,755	5,531
29	Maintenance Supervision and Engineering	38,667	3,420
30	Maintenance of Structures	245	245
31	Maintenance of Reservoirs, Dams, and Waterways	8,264	8,264
32	Maintenance of Electric Plant	229,154	76,325
33	Maintenance of Misc Hydraulic Plant	116,773	47,584
34	Total Production Expenses (total 23 thru 33)	3,680,284	2,262,279
35	Expenses per net KWh	0.0092	0.0085

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 2015/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	20.60	51.00	5
57	26	57	6
8,095	8,722	8,735	7
			8
58	25	44	9
7	4	19	10
0	0	7	11
134,497,000	74,108,000	158,999,000	12
			13
377,100	86,408	9,457	14
8,766,846	3,087,160	7,808,516	15
82,474,815	54,796,424	24,250,758	16
8,483,861	8,559,312	10,054,395	17
2,579,915	458,019	2,322,130	18
6	64	2,122	19
102,682,543	66,987,387	44,447,378	20
2,516.7290	3,251.8149	871.5172	21
			22
63,508	48,359	77,670	23
49,812	41,220	59,228	24
882,482	126,815	1,063,224	25
136,666	151,142	197,369	26
254,555	188,337	275,593	27
36,686	0	540,544	28
27,197	23,673	437,057	29
0	0	0	30
44,184	11,981	140,924	31
43,878	137,843	124,589	32
150,131	66,254	126,383	33
1,689,099	795,624	3,042,581	34
0.0126	0.0107	0.0191	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2030 Plant Name: Round Butte (d)	FERC Licensed Project No. 2030 Plant Name: Round Butte (e)	FERC Licensed Project No. 2233 Plant Name: Sullivan (f)	Line No.
Storage	Storage	Run-of-River	1
Conventional	Conventional	Conventional	2
1964	1964	1895	3
1964	1964	1953	4
324.90	216.60	15.40	5
289	0	17	6
7,555	0	7,928	7
			8
345	0	18	9
192	0	7	10
37	0	1	11
919,898,000	613,299,000	100,593,000	12
			13
3,726,481	2,521,011	572,077	14
17,466,294	11,635,965	9,367,473	15
170,100,389	111,749,374	23,569,921	16
35,997,461	24,160,922	13,813,200	17
2,328,852	1,575,723	0	18
0	0	2,630	19
229,619,477	151,642,995	47,325,301	20
706.7389	700.1062	3,073.0715	21
			22
413,752	286,199	37,141	23
297,801	219,777	34,128	24
2,584,637	1,699,167	111,624	25
241,782	158,214	115,444	26
879,205	643,969	249,256	27
35,408	26,579	0	28
196,335	153,256	36,894	29
71	71	0	30
237,663	237,663	75,188	31
543,565	356,774	169,934	32
344,572	260,008	61,627	33
5,774,791	4,041,677	891,236	34
0.0063	0.0066	0.0089	35

Schedule Page: 406 Line No.: 16 Column: d

In 2015 PGE completed construction of the floating surface collector at the North Fork Dam Forebay as prescribed by the Settlement Agreement related to the Re-licensing of the Clackamas River Hydroelectric Project – FERC Project No. 2195.

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.

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 2015/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 2015/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
			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

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 2015/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	133,798
2	Oregon Military Dept/A.F.R.C	2001	1.60	1.6	58	186,058
3	US Bank Corp Columbia Center	2001	6.40	6.2	146	488,057
4	Portland State University	2004	2.80	2.8	25	261,732
5	Oregon Military Joint Forces HQ	2005	1.60	1.6	26	191,439
6	Stimson Lumber	2005	0.57	0.5	9	159,545
7	FORTIX (ViaWest)	2005	8.50	7.7	201	525,983
8	Skyline	2005	2.00	1.8	62	201,525
9	Tri-Quint	2005	0.60	0.5	52	109,967
10	NCCWC- Filter Plant	2005	2.00	1.8	25	122,958
11	PCC Structurals	2005	1.00	0.9	15	113,874
12	Providence Portland Medical Center	2005	6.00	5.4	205	265,383
13	Salem Hospital	2006	4.00	3.6	146	188,494
14	Sunrise Water Authority Pump Station	2006	1.25	1.1	25	88,271
15	Providence Newberg Hospital	2006	1.50	1.4	43	156,833
16	Sungard DSG	2006	2.00	1.8	30	331,845
17	Kaiser Sunnyside Hospital	2007	4.50	4.1	123	352,752
18	Newberg Waste Water Treatment Plant	2008	2.00	1.8	41	154,458
19	Xerox Corp	2007	4.00	3.6	63	380,259
20	Newberg Water Treatment Plant	2007	1.00	0.9	16	78,159
21	MEMC (Solaicx)	2008	1.00	0.9	19	62,963
22	Solar World	2008	3.00	2.7	42	219,984
23	Oregon Dept of Admin Serv - Data Center	2010	2.00	1.8	31	277,254
24	Sanyo	2010	1.00	0.9	10	43,144
25	Sysco Foods	2010	2.00	1.8	28	184,779
26	Clackamas Intertie 2	2012	0.60	0.5	11	152,539
27	Dawson Creek	2012	0.80	0.7	12	95,706
28	Kaiser Westside Hospital	2012	4.00	3.6	158	408,829
29	North Plains Pump Station	2012	0.80	0.7	13	53,131
30	Oak Lodge Sanitary District	2012	2.00	1.8	35	229,144
31	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.50	1.4	15	284,255
32	Oregon State Hospital	2012	4.00	3.6	129	172,879
33	Portland Service Center	2012	0.50	0.5	9	322,856
34	Sandy Highschool	2012	1.25	1.1	21	179,894
35	TATA Communications - Hillsboro	2012	4.50	3.3	54	328,979
36	Tri-City Wastewater Treatment Plant	2012	2.50	2.3	50	161,695
37	TATA Communications - Portland	2013	6.60	5.9	71	612,983
38	City of Hillsboro Crandall Reservoir	2013	0.80	0.7	15	105,854
39	East County Courts	2013	1.50	1.4	38	316,848
40	City of Portland-Columbia Blvd WWTP	2013	1.00	0.9	20	162,234
41	Food Services of America	2013	2.00	1.8	43	230,067
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 2015/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	Avery DSG	2014	0.80	0.7	11	263,782
2	Carver (Readiness Center) DSG	2014	2.00	1.8	32	818,646
3	Juvenile Justice Center	2014	0.70	0.7	34	171,380
4	Clackamas River Water DSG	2014	2.00	1.8	87	383,435
5	Joint Water Commission	2015	5.00	4.5		325,380
6	Wapato Jail	2015	1.50	1.4	27	418,481
7	ODOT (SunWay 1)	2014	0.10	0.1	1	181,466
8	ProLogis (SunWay 2)	2015	1.09	1.0	10	860,074
9	Total					12,520,051
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						

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 2015/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.
267,597			1,547	diesel-low s	2,342	1
116,286		12,816	92,630	diesel-low s	1,379	2
76,258			32,899	diesel-low s	2,179	3
93,475		16,976	73,698	diesel-low s	2,364	4
119,649		7,514	33,350	diesel-low s	1,536	5
282,381		1,755	8,148	diesel-low s	1,721	6
61,880		22,321	121,664	diesel-low s	1,757	7
100,763			9,461	diesel-low s	1,893	8
183,279		8,730	13,671	diesel-low s	1,671	9
61,479		5,269	11,308	diesel-low s	1,521	10
113,874			5,104	diesel-low s	1,329	11
44,231		20,727	78,335	diesel-low s	1,586	12
47,124		23,536	47,681	diesel-low s	1,493	13
70,617			13,779	diesel-low s	1,250	14
104,555			11,377	diesel-low s	2,571	15
165,922			59,602	diesel-low s	1,729	16
78,389			61,626	diesel-low s	2,060	17
77,229		9,184	48,992	diesel-low s	1,457	18
95,065		4,014	47,205	diesel-low s	1,193	19
78,159		2,956	17,054	diesel-low s	1,500	20
62,963			1,658	diesel-low s	1,457	21
73,328		-2,417	30,028	diesel-low s	1,229	22
138,627			14,583	diesel-low s	1,243	23
43,144			13,263	diesel-low s	1,321	24
92,389			5,708	diesel-low s	2,336	25
254,232		1,377	7,303	diesel-low s	1,536	26
119,632			7,289	diesel-low s	2,336	27
102,207			37,783	diesel-low s	1,736	28
66,415		2,354	8,759	diesel-low s	1,557	29
114,572		9,944	17,085	diesel-low s	1,850	30
189,503			20,655	diesel-low s	2,389	31
43,220			132,217	diesel-low s	2,077	32
645,711			6,048	diesel-low s	2,643	33
143,915			23,007	diesel-low s	2,021	34
73,106			89,981	diesel-low s	2,334	35
64,678		5,408	8,669	diesel-low s	1,107	36
92,876			54,530	diesel-low s	2,457	37
132,317			7,788	diesel-low s	1,229	38
211,232			43,159	diesel-low s	2,214	39
162,234			12,427	diesel-low s	1,250	40
115,034		2,814	83,197	diesel-low s	1,207	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 2015/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.
329,728			6,828	diesel-low s	2,193	1
409,317			30,645	diesel-low s	2,193	2
228,507			8,463	diesel-low s	1,893	3
191,717		4,994	8,809	diesel-low s	1,507	4
65,076			558	diesel-low s		5
278,987			18,282	diesel-low s	1,736	6
1,814,669			77,665	solar		7
786,173				solar		8
		160,272	1,565,518			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

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	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	17.76		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	TUCANNON WF	CENTRAL FERRY BPA	230.00	230.00	H-WOOD	20.70		1
19								
20	PELTON 230KV PROJECT							
21	PELTON	ROUND BUTTE	230.00	230.00	H-WOOD	7.87		1
22								
23	NON PROJECT 230KV:							
24	BETHEL	ROUND BUTTE	230.00	230.00	H-WOOD	53.85		1
25			230.00	230.00	ST. TOWER	44.85		1
26	ROUND BUTTE	BPA REDMOND	230.00	230.00	H-WOOD	23.58		1
27	BETHEL	BPA TIE (SANTIAM)	230.00	230.00	H-WOOD	3.64		1
28	BETHEL	McLOUGHLIN	230.00	230.00	H-WOOD	35.57		1
29	CARVER	GRESHAM	230.00	230.00	H-WOOD	7.17		1
30	McLOUGHLIN	CARVER #1	230.00	230.00	H-WOOD	4.95		1
31	McLOUGHLIN	CARVER #2	230.00	230.00	ST. MONOP	4.88		1
32	BPA KEELER	ST. MARY'S W.	230.00	230.00	H-WOOD	2.89		1
33			230.00	230.00	ST. TOWER	3.78		2
34	BLUE LAKE	TROUTDALE BPA	230.00	230.00	H-WOOD	0.84		1
35			230.00	230.00	ST. MONOP	0.58		1
36					TOTAL	610.39	536.65	58

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 2015/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	PEARL BPA	SHERWOOD	230.00	230.00	ST. TOWER		4.72	2
2			230.00	230.00	ST. TOWER	0.16		1
3	GRESHAM	LINNEMAN	230.00	230.00	ST. TOWER	0.31		1
4	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER	11.51		1
5			230.00	230.00	H-TOWER	0.60		1
6	NON PROJECT 230KV							
7	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER		4.40	2
8	ST. MARY'S W.	MURRAYHILL	230.00	230.00	ST. TOWER	5.92		1
9	HORIZON	KEELER BPA	230.00	230.00	ST. MONOP	1.47		1
10	MURRAYHILL	SHERWOOD	230.00	230.00	ST. TOWER	5.68		2
11	PORT WESTWARD	TROJAN #1	230.00	230.00	ST. MONOP	18.78		1
12	PORT WESTWARD	TROJAN #2	230.00	230.00	ST. MONOP	9.39		1
13	TROJAN	ST. MARY'S W.	230.00	230.00	H-WOOD	0.10		1
14			230.00	230.00	ST. TOWER	8.07		1
15					ST.TOWER		32.20	1
16	TROJAN	RIVERGATE	230.00	230.00	ST. TOWER	32.20		2
17			230.00	230.00	ST. TOWER	2.88		2
18								
19	Tot Nonproj 230kv Costs							
20								
21	GRESHAM	TROUTDALE BPA	230.00	230.00	ST. TOWER		0.43	1
22	BOARDMAN	PPL DALREED	230.00	230.00	H-WOOD	16.76		1
23								
24	Tot 230KV LINE EXPENSES							
25								
26	PROJECT 115 KV LINES							
27	FARADAY	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		1
28	NORTH FORK	FARADAY	115.00	115.00	H-WOOD	2.79		1
29	OAK GROVE	FARADAY	115.00	115.00	DC LATTICE	18.68		2
30	OAK GROVE	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		2
31			115.00	115.00	DC LATTICE	18.68		2
32	Tot 115KV LINE EXPENSES							
33								
34								
35								
36					TOTAL	610.39	536.65	58

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	17,485,375	17,760,802					3
		148,889	148,889					4
		148,889	148,889					5
	5,904		5,904					6
1780MCMACSR		5,883,809	5,883,809					7
		3,624,934	3,624,934					8
								9
								10
								11
								12
								13
	1,194,326	43,101,062	44,295,388					14
				1,931,590	694,305	801,728	3,427,623	15
								16
		3,040,852	3,040,852					17
795KCMAAC		2,124,113	2,124,113					18
								19
								20
795MCMACSR	7,579	356,927	364,506					21
								22
								23
1272MCMACSR								24
1272MCMACSR								25
795MCMACSR								26
795MCMACSR								27
1272MCMACSR								28
1272MCMAAC								29
1272MCMAAC								30
1272MCMACSS								31
1590MCMACSRTW								32
1590MCMACSRTW								33
1780MCMACSR								34
								35
	10,273,261	149,501,696	159,774,957	2,426,061	872,041	1,034,370	4,332,472	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 2015/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.
2388MCMAACTW								1
2388MCMAACTW								2
1272MCMAAC								3
1272MCMAAC								4
1780MCMACSR								5
								6
1272MCMAAC								7
1272MCMAAC								8
1272MCMACSS								9
1272MCMAAC								10
2156MCMACSS								11
2156MCMACSS								12
1272MCMAAC								13
1590MCMAAC								14
1590MCMAAC								15
1590MCMAAC								16
1272MCMACSR								17
								18
	8,584,052	67,985,066	76,569,118					19
								20
954KCMACSR								21
795KCMAAC		1,074,170	1,074,170					22
								23
				494,471	177,736	161,700	833,907	24
								25
								26
795KCMACSR		871,841	871,841					27
556KCMACSR	120,248	621,351	741,599					28
250CU	12,477	503,937	516,414					29
795KCMACSR								30
250CU	22,295	884,661	906,956					31
						70,942	70,942	32
								33
								34
								35
	10,273,261	149,501,696	159,774,957	2,426,061	872,041	1,034,370	4,332,472	36

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

In 1985, PGE sold a 15% undivided interest in the Boardman Plant and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under the terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. This transaction was approved by the FERC on December 19, 2013 through Docket EC14-13-000.

The original cost of the 15% of the Boardman Plant and the 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line at December 31, 2013 was estimated at $96 million and $2 million, respectively. It was also estimated that these assets were fully depreciated at the time the acquisition was executed since it coincided with the expiration of various agreements under the terms of the original 1985 transaction.

The proposed final accounting entries associated with this transaction were submitted to the FERC on June 27, 2014, in compliance with the accounting under the Uniform System of Accounts (Docket AC14-129-000). On September 29, 2014, FERC approved the final proposed journal entries. In September 2014, the final accounting entries were executed, which increased both Electric plant in service (Account 101) and Accumulated provision for depreciation (Account 108) by $97,861,972 (Steam $94,061,144 and Transmission $3,800,827) with corresponding offsets to Electric plant purchased or sold (Account 102).

In December 2014 PGE acquired an additional 10% undivided interest from another co-owner in the Boardman Plant, and associated equipment and facilities, as well as certain contracts and other rights related to that co-owner's ownership interest in the Boardman Plant.

The original cost of the 10% share of the assets acquired at December 31, 2014 was estimated at $67 million.

On September 19, 2014, PGE filed an application requesting authorization for the acquisition of the rights, titles, and interests associated with this transaction pursuant to section 203(a)(1) of the Federal Power Act (FPA), including proposed accounting entries. On November 14, 2014, the FERC concluded that the proposed transaction was consistent with public interest and authorized the transaction (Docket EC14-147-000). In December 2014, accounting entries were executed which increased Electric plant in service (Account 101) by $67,211,321 (Steam Plant $65,882,727 and Transmission $1,328,594), Accumulated provision for depreciation (Account 108) by $47,707,066 (Steam $46,764,020 and Transmission $943,046), and Construction work in progress (Account 107) by $372,000 with corresponding offsets to Electric plant acquisition adjustments (Account 114).

On April 20, 2015 (Docket EC14-147-000) PGE submitted proposed final journal entries for acceptance as prescribed under Electric Plant Instruction No. 5 and Account 102, Electric plant purchased or sold. Based on discussion with FERC Commission staff, PGE re-filed on May 27, 2015 (Docket AC15-110-000) clearing the negative acquisition recorded to Account 114, Electric plant acquisition adjustment immediately instead of amortizing the balance over the remaining life of the plant. On July 6, 2015 (Docket EC14-147-000) the FERC approved the proposed journal entries.

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. 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.: 21   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: 422.1   Line No.: 1   Column: a

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

Schedule Page: 422.1   Line No.: 21   Column: a

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

Schedule Page: 422.1   Line No.: 22   Column: a

Jointly owned with Idaho Power Company. 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 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	No addtions in 2015						
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	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

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

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 2015/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	9 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	13.00	
27	Cornell, Portland, OR	Distrib./unattended	115.00	13.00	
28	Curtis, Portland, OR	Distrib./unattended	115.00	13.00	
29	Dayton, near Dayton, OR	Distrib./unattended	115.00	57.00	13.00
30	Dayton, near Dayton, OR	Distrib./unattended	57.00	13.00	
31	Delaware, Portland, OR	Distrib./unattended	115.00	13.00	
32	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 2015/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	Hayden Island, near Portland, OR	Distrib./unattended	115.00	13.00	
18	Hemlock, Portland, OR	Distrib./unattended	115.00	13.00	
19	Hillcrest, Salem, OR	Distrib./unattended	115.00	13.00	
20	Hillsboro, Hillsboro, OR	Distrib./unattended	57.00	13.00	
21	Hogan North, Gresham, OR	Distrib./unattended	115.00	13.00	
22	Hogan South, Gresham, OR	Distrib./unattended	115.00	57.00	13.00
23	Hogan South, Gresham, OR	Distrib./unattended	115.00	13.00	
24	Holgate, Portland, OR	Distrib./unattended	57.00	13.00	
25	Huber, near Beaverton, OR	Distrib./unattended	115.00	13.00	
26	Indian, near Salem, OR	Distrib./unattended	115.00	13.00	
27	Island, near Milwaukie, OR	Distrib./unattended	115.00	13.00	
28	Jennings Lodge, Jennings Lodge, OR	Distrib./unattended	115.00	13.00	
29	Kelley Point, Portland, OR	Distrib./unattended	115.00	13.00	
30	Kelly Butte, Portland, OR	Distrib./unattended	115.00	13.00	
31	King City, near King City, OR	Distrib./unattended	115.00	13.00	
32	Leland, Oregon City, OR	Distrib./unattended	57.00	13.00	
33	Lents, near Portland, OR	Distrib./unattended	115.00	13.00	
34	Lents, near Portland, OR	Distrib./unattended	57.00	11.00	
35	Liberty, Salem, OR	Distrib./unattended	115.00	13.00	
36	Main, Hillsboro, OR	Distrib./unattended	57.00	13.00	
37	Market Street, Salem, OR	Distrib./unattended	115.00	12.50	
38	McClain, Salem, OR	Distrib./unattended	57.00	13.00	
39	Meridian, near Tualatin, OR	Distrib./unattended	115.00	13.00	
40	Middle Grove, near Middle Grove, OR	Distrib./unattended	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 2015/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	Midway, near Portland, OR	Distrib./unattended	115.00	13.00	
2	Mill Creek, near Salem, OR	Distrib./unattended	115.00	13.00	
3	Mobile sub No. 1, OR	Distrib./unattended	115.00	57.00	13.00
4	Mobile Sub No. 3, OR	Distrib./unattended	115.00	57.00	12.50
5	Mobile Sub No. 4, OR	Distrib./unattended	115.00	57.00	13.00
6	Molalla, Molalla, OR	Distrib./unattended	57.00	13.00	
7	Mt. Angel, Mt. Angel, OR	Distrib./unattended	57.00	13.00	
8	Mt. Pleasant, Oregon City, OR	Distrib./unattended	115.00	13.00	
9	Multnomah, Portland, OR	Distrib./unattended	115.00	13.00	
10	Newberg, Newberg, OR	Distrib./unattended	115.00	13.00	
11	North Marion, near Woodburn, OR	Distrib./unattended	57.00	13.00	
12	North Plains, North Plains, OR	Distrib./unattended	57.00	13.00	
13	Northern, Portland, OR	Distrib./unattended	57.00	11.00	
14	Oak Hills, near Beaverton, OR	Distrib./unattended	115.00	13.00	
15	Oregon City - BPA, near Wilsonville, OR	Distrib./unattended	57.00		
16	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	57.00	13.00
17	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
18	Orient, near Gresham, OR	Distrib./unattended	57.00	13.00	
19	Oswego, Lake Oswego, OR	Distrib./unattended	115.00	13.00	
20	Oxford, Salem, OR	Distrib./unattended	115.00	13.00	
21	Peninsula Park, Portland, OR	Distrib./unattended	115.00	13.00	
22	Pleasant Valley, near Portland, OR	Distrib./unattended	115.00	12.50	
23	Portsmouth, Portland, OR	Distrib./unattended	115.00	13.00	
24	Progress, near Tigard, OR	Distrib./unattended	115.00	13.00	
25	Raleigh Hills, near Portland, OR	Distrib./unattended	115.00	13.00	
26	Ramapo, near Portland, OR	Distrib./unattended	115.00	13.00	
27	Redland, near Oregon City, OR	Distrib./unattended	115.00	13.00	
28	Reedville, near Beaverton, OR	Distrib./unattended	115.00	13.00	
29	Rhododendron Switching, OR	Distrib./unattended	57.00		
30	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	13.00	
31	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	11.00	
32	Riverview, Portland, OR	Distrib./unattended	115.00	13.00	
33	Rockwood, near Gresham, OR	Distrib./unattended	115.00	13.00	
34	Rosemont, near Lake Oswego, OR	Distrib./unattended	115.00	13.00	
35	Roseway, Hillsboro, OR	Distrib./unattended	115.00	13.00	
36	Ruby,Gresham, OR	Distrib./unattended	115.00	13.00	
37	Salem-PGE, near Salem, OR	Distrib./unattended	57.00	13.00	
38	Sandy, Sandy, OR	Distrib./unattended	57.00	13.00	
39	Scappoose, Scappoose, OR	Distrib./unattended	115.00		
40	Scholls Ferry, Beaverton, 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 2015/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	Scoggin, near Gaston, OR	Distrib./unattended	57.00	13.00	
2	Sellwood, Portland, OR	Distrib./unattended	115.00	57.00	13.00
3	Sellwood, Portland, OR	Distrib./unattended	115.00	13.00	
4	Sheridan, Sheridan, OR	Distrib./unattended	57.00	13.00	
5	Shute, Hillsboro, OR	Distrib./unattended	115.00	34.50	
6	Silverton, Silverton, OR	Distrib./unattended	57.00	13.00	
7	Six Corners, Six Corners, OR	Distrib./unattended	115.00	13.00	
8	Springbrook, Newberg, OR	Distrib./unattended	115.00	13.00	
9	Springdale, near Springdale, OR	Distrib./unattended		12.50	
10	St. Helens, near St. Helens, OR	Distrib./unattended	115.00		
11	St. Johns-BPA, near Portland, OR	Distrib./unattended		11.00	
12	St. Louis, St. Louis, OR	Distrib./unattended	57.00	13.00	
13	St. Marys, East Yard, near Beaverton, OR	Distrib./unattended	115.00	13.00	
14	Stephens, Portland, OR	Distrib./unattended	57.00	11.00	
15	Sullivan, West Linn, OR	Distrib./unattended	115.00	13.00	
16	Summit, Government Camp, OR	Distrib./unattended	57.00	13.00	
17	Summit, Government Camp, OR	Distrib./unattended	24.00	13.00	
18	Sunset, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
19	Sunset, near Hillsboro, OR	Distrib./unattended	115.00	34.50	
20	Swan Island, Portland, OR	Distrib./unattended	115.00	13.00	
21	Sylvan, near Portland, OR	Distrib./unattended	115.00	13.00	
22	Tabor, Portland, OR	Distrib./unattended	115.00	13.00	
23	Tabor, Portland, OR	Distrib./unattended	57.00		
24	Tektronix, Beaverton, OR	Distrib./unattended	115.00	13.00	
25	Tigard, Tigard, OR	Distrib./unattended	115.00	12.50	
26	Town Center, Portland, OR	Distrib./unattended	115.00	13.00	
27	Tualitin, Tualitin, OR	Distrib./unattended	115.00	13.00	
28	Twilight, Canby, OR	Distrib./unattended	57.00	13.00	
29	University, Salem, OR	Distrib./unattended	115.00	13.00	
30	Urban, Portland, OR	Distrib./unattended	115.00	13.00	
31	Waconda, near Hopmere, OR	Distrib./unattended	57.00	12.50	
32	Wallace, Salem, OR	Distrib./unattended	115.00	13.00	
33	Welches, near Welches, OR	Distrib./unattended	57.00	24.00	
34	Welches, near Welches, OR	Distrib./unattended	57.00	13.00	
35	West Portland, Lower Yard, near Tigard, OR	Distrib./unattended	115.00		
36	West Portland, Upper Yard, near Tigard, OR	Distrib./unattended	115.00	13.00	
37	West Union, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
38	Willamina, near Willamina, OR	Distrib./unattended	57.00	13.00	
39	Willbridge, Portland, OR	Distrib./unattended	115.00	11.00	
40	Wilsonville, near Wilsonville, OR	Distrib./unattended	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 2015/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	Woodburn, Woodburn, OR	Distrib./unattended	57.00	13.00	
2	Yamhill, near Yamhill, OR	Distrib./unattended	57.00	13.00	
3					
4					
5					
6	Bakeoven, BPA, near Bakeoven, OR	Transm./unattended	500.00		
7	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	13.00	
8	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	24.00	
9	Bethel, Salem, OR	Transm./unattended	230.00	115.00	13.00
10	Bethel, Salem, OR	Transm./unattended	115.00	57.00	13.00
11	Bethel, Salem, OR	Transm./unattended	115.00	13.00	
12	Biglow Canyon Wind Farm, Wasco, OR	Transm./unattended	230.00	34.50	13.80
13	Blue Lake, Troutdale, OR	Transm./unattended	230.00	115.00	13.00
14	Blue Lake, Troutdale, OR	Transm./unattended	115.00	13.00	
15	Boardman, near Boardman, OR	Transm./unattended	500.00	24.00	
16	Boardman, OR	Transm./unattended	230.00	7.20	
17	Boardman, OR	Transm./unattended	24.00	7.20	
18	Broadview Subst. near Broadview, MT	Transm./unattended	500.00	230.00	
19	Captain Jack, BPA, near Malin, OR	Transm./unattended	500.00		
20	Carver, Carver, OR	Transm./unattended	230.00	115.00	13.00
21	Carver, Carver, OR	Transm./unattended	115.00	13.00	
22	Colstrip Plant, near Colstrip, MT	Transm./unattended	500.00	26.00	
23	Colstrip Subst. near Colstrip, MT	Transm./unattended	500.00	230.00	
24	Coyote Springs, Boardman, OR	Transm./unattended	500.00		
25	Faraday, Switchyard, near Estacada, OR	Transm./unattended	115.00	57.00	12.50
26	Faraday, Switchyard, near Estacada, OR	Transm./unattended	57.00	11.00	
27	Faraday Plant, near Estacada, OR	Transm./unattended	115.00	12.50	
28	Fort Rock, approx 12 mi NE of Silver Lake, OR	Transm./unattended	500.00		
29	Gresham, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
30	Grizzly, BPA, near Madras, OR	Transm./unattended	500.00		
31	Horizon, Hillsboro, OR	Transm./unattended	230.00	115.00	13.00
32	Keeler, BPA, Hillsboro, OR				
33	Linneman, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
34	Malin, BPA, near Malin, OR	Transm./unattended	500.00		
35	McLoughlin, near Oregon City, OR	Transm./unattended	230.00	115.00	13.00
36	Monitor, near Monitor, OR	Transm./unattended	230.00	57.00	13.00
37	Murrayhill, Beaverton, OR	Transm./unattended	230.00	115.00	13.00
38	Murrayhill, Beaverton, OR	Transm./unattended	115.00	13.00	
39	North Fork, near Estacada, OR	Transm./unattended	115.00	13.00	
40	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	13.00	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	11.00	
2	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	11.00	
3	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	0.48	
4	Pearl, BPA, near Wilsonville, OR	Transm./unattended	230.00		
5	Pelton, near Madras, OR	Transm./unattended	230.00	13.00	
6	Pelton, near Madras, OR	Transm./unattended	13.00	13.00	
7	Port Westward, near Clatskanie, OR	Transm./unattended	230.00	18.00	16.50
8	River Mill, near Estacada, OR	Transm./unattended	57.00	11.00	
9	Rivergate North Yard, near Portland, OR	Transm./unattended	230.00	115.00	13.00
10	Round Butte, near Madras, OR	Transm./unattended	500.00	230.00	12.50
11	Round Butte, near Madras, OR	Transm./unattended	230.00	12.50	
12	Sand Springs, 22 mi E/22 mi S of Bend, OR	Transm./unattended	500.00		
13	Sherwood, near Six Corners, OR	Transm./unattended	230.00	115.00	13.00
14	Slatt, BPA, Arlington, OR	Transm./unattended	500.00		
15	St. Marys, West Yard, near Beaverton, OR	Transm./unattended	230.00	115.00	13.00
16	Sullivan, West Linn, OR	Transm./Unattended	57.00	4.15	
17	Sycan, 27 mi S of Silver Lake, OR	Transm./unattended	500.00		
18	Trojan, near Rainier, OR	Transm./unattended	230.00	12.50	
19	Tucannon Mullan Switchyard, Dayton, WA	Transm./unattended	230.00	34.50	13.00
20	TOTAL MVa		29028.00	4955.53	366.80
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
69	9		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
42	2		Capacitor Banks	2	3,600	7
34	2		Capacitor Banks	4	12,000	8
66	3		Capacitor Banks	4	12,000	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
17	1		Capacitor Banks	2	6,000	28
125	1					29
22	2		Capacitor Banks	4	6,000	30
22	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

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
45	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	6,600	16
34	2		Capacitor Banks	4	12,000	17
28	1		Capacitor Banks	2	6,000	18
28	1		Capacitor Banks	2	6,000	19
43	2		Capacitor Banks	4	14,400	20
56	2		Capacitor Banks	4	12,600	21
125	3					22
56	2		Capacitor Banks	4	13,200	23
39	2		Capacitor Banks	2	7,200	24
56	2		Capacitor Banks	2	6,000	25
56	2		Capacitor Banks	3	10,800	26
45	2		Capacitor Banks	4	12,000	27
53	2					28
56	2		Capacitor Banks	4	12,000	29
45	2		Capacitor Banks	2	6,000	30
50	2		Capacitor Banks	4	14,400	31
28	1		Capacitor Banks	2	6,000	32
22	1					33
10	1					34
50	2		Capacitor Banks	3	10,200	35
84	3		Capacitor Banks	6	20,400	36
28	1		Capacitor Banks	2	6,000	37
23	3					38
84	3		Capacitor Banks	6	18,600	39
53	2		Capacitor Banks	4	12,000	40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
34	2		Capacitor Banks	1	3,600	1
17	1		Capacitor Banks	2	6,000	2
15	1					3
29	1					4
34	1					5
42	2		Capacitor Banks	4	9,000	6
20	1		Capacitor Banks	3	15,000	7
45	2		Capacitor Banks			8
39	2		Capacitor Banks	3	9,600	9
45	2		Capacitor Banks	4	12,000	10
31	3		Capacitor Banks	3	15,000	11
20	1		Capacitor Banks	4	18,000	12
28	2					13
56	2		Capacitor Banks	4	14,400	14
						15
280	2					16
81	3		Capacitor Banks	6	18,600	17
15	2					18
34	2		Capacitor Banks	2	7,200	19
50	2		Capacitor Banks	4	12,300	20
28	1		Capacitor Banks	2	6,000	21
56	2		Capacitor Banks	4	12,000	22
28	1					23
50	2		Capacitor Banks	4	13,800	24
28	1		Capacitor Banks	2	6,600	25
28	1		Capacitor Banks	2	6,000	26
22	1					27
84	3		Capacitor Banks	6	18,000	28
						29
22	1		Capacitor Banks	2	7,200	30
22	1		Capacitor Banks	2	6,716	31
28	1		Capacitor Banks	2	6,000	32
78	3		Capacitor Banks	5	15,000	33
28	1		Capacitor Banks	2	6,000	34
28	1		Capacitor Banks	2	6,000	35
28	1		Capacitor Banks	2	6,000	36
45	2		Capacitor Banks	4	12,000	37
28	1		Capacitor Banks	2	6,000	38
						39
28	1		Capacitor Banks	2	6,000	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/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.
13	2		Capacitor Banks	1	10,800	1
140	1		Capacitor Banks	1	24,000	2
28	1		Capacitor Banks	2	6,000	3
17	1		Capacitor Banks	3	19,200	4
100	2		capacitor Banks	2	9,000	5
33	3		Capacitor Banks	2	3,600	6
49	2		Capacitor Banks	2	6,000	7
56	2		Capacitor Banks	5	36,000	8
						9
			Capacitor Banks	1	24,000	10
						11
24	2		Capacitor Banks	2	7,200	12
56	2		Capacitor Banks	4	12,000	13
100	2		Capacitor Banks	2	16,800	14
45	2		Capacitor Banks	5	36,000	15
8	1	1				16
14	1					17
400	8		Capacitor Banks	25	150,000	18
250	2					19
53	2		Capacitor Banks	4	12,000	20
22	1		Capacitor Banks	2	6,000	21
22	1		Capacitor Banks	2	6,000	22
						23
56	2		Capacitor Banks	4	12,000	24
45	2		Capacitor Banks	4	12,000	25
56	2		Capacitor Banks	2	6,000	26
56	2		Capacitor Banks	4	13,200	27
28	1		Capacitor Banks	3	19,200	28
22	1		Capacitor Banks	2	7,200	29
112	4		Capacitor Banks	7	43,200	30
41	2		Capacitor Banks	2	6,000	31
28	1		Capacitor Banks	2	6,000	32
10	1		Capacitor Banks	1	12,000	33
18	2		Capacitor Banks	2	6,000	34
			Capacitor Banks	1	24,000	35
56	2		Capacitor Banks	4	13,200	36
28	1		Capacitor Banks	3	15,200	37
24	2		Capacitor Banks	3	7,800	38
20	1					39
84	3		Capacitor Banks	6	18,000	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)	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)	
42	2		Capacitor Banks	4	13,200	1
15	2		Capacitor Banks	1	1,800	2
						3
						4
						5
						6
464	4					7
170	1					8
502	2					9
140	1					10
28	1		Capacitor Banks	2	6,000	11
480	3					12
320	1					13
28	1		Capacitor Banks	2	6,000	14
685	3					15
55	1					16
55	1					17
80	3					18
						19
640	2					20
56	2		Capacitor Banks	4	12,000	21
164	3					22
100	2					23
300	3					24
140	1					25
32	2					26
27	1					27
			Series Capacitor	1	363,000	28
572	2					29
						30
320	1					31
						32
168	1					33
			Reactors	3	180,000	34
640	2					35
125	1					36
320	1					37
56	2		Capacitor Banks	3	10,800	38
53	3	1				39
8	1					40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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.
64	2					1
						2
						3
						4
164	4					5
3	1					6
450	3					7
32	2					8
520	4		Capacitor Banks	1	22,000	9
561	3		Reactors	12	180,000	10
394	4	2				11
			Series Capacitor	1	546,000	12
640	2					13
						14
960	3		Capacitor Banks	3	108,000	15
33	1					16
			Series Capacitor	1	546,000	17
56	2					18
320	2		Capacitors/Reactors	6	90,000	19
18374	360	4		425	3,602,486	20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426 Line No.: 19 Column: a
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.

Schedule Page: 426 Line No.: 20 Column: a
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating 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 regulating equipment.

Schedule Page: 426.2 Line No.: 15 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.: 29 Column: a
Switching only.

Schedule Page: 426.2 Line No.: 39 Column: a
Switching only. Distribution owned by Columbia River PUD.

Schedule Page: 426.3 Line No.: 9 Column: a
Regulating only.

Schedule Page: 426.3 Line No.: 10 Column: a
Switching only. Distribution owned by Columbia River PUD.

Schedule Page: 426.3 Line No.: 11 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.: 23 Column: a
Switching only.

Schedule Page: 426.3 Line No.: 35 Column: a
Switching only.

Schedule Page: 426.4 Line No.: 6 Column: a
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.

Schedule Page: 426.4 Line No.: 15 Column: a
Jointly owned with Idaho Power Company. PGE has an 90% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 16 Column: a
Jointly owned with Idaho Power Company. PGE has an 90% share of the jointly owned capacity, 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 17 Column: a
Jointly owned with Idaho Power Company. PGE has an 90% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 18 Column: a
Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 16% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 19 Column: a
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.

Schedule Page: 426.4 Line No.: 22 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.: 23 Column: a
Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 14% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 24 Column: a

Contribution in aid of construction made to Bonneville Power Administration in 2006 in the amount of 261,281 to FERC account 353.
Contribution in aid of construction made to Bonneville Power Administration in 1995 in the amount of 1,115,709 to FERC account 353.

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

Line compensation only.

Schedule Page: 426.4 Line No.: 30 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.: 32 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.: 34 Column: a

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to Boneville Power Administration recorded to FERC account 353.

Schedule Page: 426.5 Line No.: 4 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.: 5 Column: a

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

Schedule Page: 426.5 Line No.: 6 Column: a

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

Schedule Page: 426.5 Line No.: 11 Column: a

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

Schedule Page: 426.5 Line No.: 12 Column: a

Line compensation only.

Schedule Page: 426.5 Line No.: 14 Column: a

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.

Schedule Page: 426.5 Line No.: 17 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 2015/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	951,948
7				
8	Construction Work in Progress	Sunway 2, LLC	107	1,296,588
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22	Administrative Services	Salmon Springs Hospitality Group	186	936,072
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 8 Column: d

On January 5, 2015, PGE acquired the assets and liabilities of Sunway 2, LLC, a variable interest entity, at net book value. The entity was subsequently dissolved.

INDEX

Schedule | Page No.