Portland General Electric
121 SW Salmon Street • Portland, Ore. 97204
PortlandGeneral.com

May 8, 2019

Electronic Mail
puc.filingcenter@state.or.us

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
PO Box 1088
Salem, OR 97308-1088

RE: Supplement to PGE FERC Form 1 and Oregon Supplemental

PGE filed its RE 54 Report on May 1, 2019 and supplements that filing with PGE's 2018 'pre-closing trial balance'. Enclosed are two CDs as directed in the March 25, 2019 letter from the OPUC. As directed by Staff, the CDs are being provided to the 'Filing Center Annual Reports, PO Box 1088, Salem, OR 97308-1088.

The CDs contain:

1) PGE's final pre-closing trial balance by FERC Account in Excel format

If you have any questions or require further information, please call me at 503-464-7805. Please direct all formal correspondence, questions, or requests to the following e-mail address: pge.opuc.filings@pgn.com.

Sincerely,

Stefan Brown
Manager, Regulatory Affairs

SB/lh

cc: Marianne Gardner, OPUC

cc: CDs provided to OPUC Filing Center (Annual Reports) e-FILING REPORT COVER SHEET

COMPANY NAME: Portland General Electric - Supplement to Annual Report for the year ending 12/31/18

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☒ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☒ Yes, report docket number: RE- 54(7)

Report is required by: ☐ OAR 860-027-0070
☒ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☒ No ☐ Yes, docket number:

List Key Words for this report. We use these to improve search results.

1) PGE's Supplement to Oregon Annual Report - 'pre-closing trial balance'

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

Print

THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)

Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)

Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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** 2018/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/forms/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/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.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 1,168 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 168 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	02 Year/Period of Report
Portland General Electric Company	End of 2018/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	06 Title of Contact Person
Jardon Jaramillo	Controller & Asst. Treasurer

07 Address of Contact Person *(Street, City, State, Zip Code)*
121 SW Salmon Street, Portland, Oregon, 97204

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(503) 464-7051	(1) [X] An Original (2) [ ] A Resubmission	/ /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
James F. Lobdell		
02 Title		
SVP Finance, CFO, and Treasurer	James F. Lobdell	04/12/2019

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

Name of Respondent 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 2018/Q4

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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".

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.

Jardon Jaramillo
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 natrual gas in an effort to obtain reasonably-priced power to serve 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 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 2018/Q4

CONTROL OVER RESPONDENT

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

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	121 SW Salmon Street Corporation	Company has purchased the	100	
2		headquarters complex in		
3		Portland, Oregon and leases		
4		the complex to the Respondent		
5				
6	World Trade Center Northwest Coporation	Company is the holder of the	100	
7	(A wholly-owned subsidiary of 121 SW Salmon	World Trade Center Franchise		
8	Street Corporation)			
9				
10	Salmon Springs Hospitality Group	Company provides food	100	
11		catering services		
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Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/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	Maria M. Pope	749,904
2			
3	Senior Vice President of Finance, Chief Financial	James F. Lobdell	442,587
4	Officer and Treasurer		
5			
6	Vice President, General Counsel and Corporate	Lisa A. Kaner	363,462
7	Compliance Officer		
8			
9	Vice President, Utility Technical Services	William O. Nicholson	329,608
10			
11	Vice President, Public Policy	W. David Robertson	319,940
12			
13	Vice President, Customer Strategies and Business	Carol A. Dillin	226,314
14	Development		
15			
16	Vice President, Utility Operations	Bradley Y. Jenkins	309,231
17			
18	Vice President, Grid Architecture, Integration &	Larry N. Bekkedahl	307,895
19	Systems Operations		
20			
21	Vice President, Information Technology and Chief	John Kochavatr	288,115
22	Information Officer		
23			
24	Vice President, Customer Solutions	Kristin A. Stathis	273,163
25			
26	Vice President, Human Resources, Diversity,	Anne E. Mersereau	271,329
27	Equity & Inclusion		
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Schedule Page: 104 Line No.: 1 Column: c

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

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

Retired from company effective September 12, 2018.

Schedule Page: 104 Line No.: 21 Column: b

Appointed to position effective February 1, 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	Retired Executive Vice President, First Chicago NBD Corp.	
3		
4	Rodney L. Brown, Jr.	Seattle, Washington
5	Founding Partner, Cascadia Law Group PLLC	
6		
7	Jack E. Davis	Scottsdale, Arizona
8	Chair of the Board, Portland General Electric	
9	Retired Chief Executtive Officer, Arizona Public Service Co.	
10		
11	David A. Dietzler	Lake Oswego, Oregon
12	Retired Partner, KPMG LLP	
13		
14	Kirby A. Dyess	Beaverton, Oregon
15	Principal, Austin Capital Management LLC	
16		
17	Mark B. Ganz	Portland, Oregon
18	President and Chief Executive Officer,	
19	Cambia Health Solutions, Inc.	
20		
21	Kathryn J. Jackson	Pittsburg, Pennsylvania
22	Director, Energy & Technology Consulting, KeySource, Inc.	
23		
24	Neil J. Nelson	Portland, Oregon
25	President and Chief Executive Officer, Siltronic Corp.	
26		
27	M. Lee Pelton	Boston, Massachusetts
28	President, Emerson College	
29		
30	Maria M. Pope	Portland, Oregon
31	President and Chief Executive Officer,	
32	Portland General Electric	
33		
34	Charles W. Shivery	Longboat Key, Florida
35	Retired President and Chief Executive Officer,	
36	Northeast Utilities	
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Schedule Page: 105 Line No.: 30 Column: a

Appointed to position effective January 1, 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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

Does the respondent have formula rates?

[ ] Yes
[X] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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

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

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

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

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

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

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

1. None

2. None

3. None

4. None

5. None

6. Pursuant to PGE's application, the FERC, on January 3, 2018, issued an order in Docket No. ES17-59-000 that authorizes the Company to issue up to $900 million of short-term debt through February 6, 2020. The authorization provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

As of December 31, 2018, PGE had a $500 million revolving credit facility scheduled to expire in November 2021. On January 15, 2019, PGE executed an amendment to the credit facility extending the termination date to November 14, 2022 and allowing for unlimited extension requests, provided that Lenders with a pro-rata share of more than 50%, approve the extension request. The revolving credit facility supplements operating cash flows and provides a primary source of liquidity. Pursuant to the terms of the agreement, the revolving credit facility may be used as backup for commercial paper borrowings, to permit the issuance of standby letters of credit, and to provide cash for general corporate purposes. 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.

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

As of December 31, 2018, PGE had no borrowings outstanding, and no commercial paper or letters of credit issued under the revolving credit facility. As a result, the aggregate, unused available credit capacity was $500 million.

In addition, PGE has four letter of credit facilities under which the Company can request letters of credit for original terms not to exceed one year. These facilities provide for a total capacity of $220 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these four facilities, letters of credit for a total of $84 million were outstanding, as of December 31, 2018.

During 2018, PGE issued a total of $75 million of FMBs at an interest rate of 4.47% with a maturity date of 2048, under authority granted under Public Utility Commission of Oregon (OPUC) Order 16-152, dated April 21, 2017. In addition, the Company repaid $24 million of Pollution Control Revenue Bonds that were early redeemed in October 2018.

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, 2018, 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:

Trojan Investment Recovery Class Actions

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 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 2003, in two separate legal proceedings, lawsuits were filed against PGE on behalf of two classes of electric service customers: i) Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court; and ii) Morgan v. Portland General Electric Company, Marion County Circuit Court. 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 2006, the Oregon Supreme Court (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.

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 2013 and by the OSC in 2014.

In 2015, based on a motion filed by PGE, the Marion County Circuit Court (Circuit Court) lifted the abatement and in July 2015, the Circuit Court heard oral argument on the Company's motion for Summary Judgment. In March 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. In April 2016, the plaintiffs appealed the Circuit Court dismissal to the Court of Appeals for the State of Oregon. A Court of Appeals decision remains pending.

PGE believes that the 2014 OSC decision and the recent Circuit Court decisions have reduced the risk of a loss to the Company beyond the amounts previously recorded and discussed above. However, because the class actions remain subject to a decision in the appeal, 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.

Carty

In the Matter of an Arbitration Under the Rules of the International Chamber of Commerce's Court of Arbitration, International Chamber of Commerce's Court of Arbitration.

Portland General Electric Company v. Liberty Mutual Insurance Company and Zurich American Insurance Company, U.S. District Court of the District of Oregon.

Portland General Electric Company v. Abeinsa EPC LLC, Abener Construction Services, LLC (formerly known as Abener Engineering and Construction Services, LLC), Teyma Construction USA LLC, and Abeinsa Abener Teyma General Partnership, U.S. District Court of the District of Oregon.

In 2013, PGE entered into a turnkey engineering, procurement, and construction agreement (Construction Agreement) with Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership (collectively, the Contractor), affiliates of Abengoa S.A., for the construction of the Carty natural gas-fired generating plant (Carty) located in Eastern Oregon. Liberty Mutual Insurance Company and Zurich American Insurance Company (together, the Sureties) provided a performance bond of $145.6 million (Performance Bond) in connection with the Construction Agreement. PGE, the Contractor, Abengoa S.A., and the Sureties are hereinafter collectively referred to as the Parties.

In December 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement. Following termination of the Construction Agreement, PGE brought on new contractors and construction resumed.

Carty was placed into service on July 29, 2016 and the Company began collecting its revenue requirement in customer prices on August 1, 2016, as authorized by the OPUC, based on the approved capital cost of $514 million. Actual costs for the construction of Carty exceeded the approved amount and, as of June 30, 2018, PGE had capitalized $640 million to Electric utility plant.

The excess costs resulted from various matters relating to the resumption of construction activities following the termination of the Construction Agreement.

The Company sought recovery of excess construction costs and other damages pursuant to breach of contract claims against the Contractor and claims against the Sureties pursuant to the Performance Bond. The Sureties denied liability in whole under the Performance Bond, and the Contractor filed claims against the Company alleging wrongful termination of contract and related damages.

Various actions relating to this matter were filed in the U.S. District Court for the District of Oregon, in the Ninth Circuit Court of Appeals, and in the International Chamber of Commerce’s Court of Arbitration.

As a result of the foregoing events, PGE has incurred a higher cost of service than what is reflected in the current authorized revenue requirement amount, primarily due to higher depreciation, interest, and legal expenses. These incremental expenses are recognized in the Company’s current results of operations. Such incremental expenses were $8 million and $14 million for the years ended December 31, 2018 and 2017, respectively.

On July 16, 2018, the Parties reached a settlement to resolve all claims relating to Carty construction between the Company and each of the Contractor, Abengoa S.A., and the Sureties. Under the terms of the settlement: i) the Sureties paid $130 million to PGE; and ii) the Contractor, Abengoa S.A., and the Sureties released all claims against the Company arising out of the Carty construction, and in return, PGE released all such claims against the Contractor, Abengoa S.A., and the Sureties.

The Company applied $120 million to reduce Electric utility plant, net for undepreciated incremental construction costs, thus eliminating ongoing excess depreciation and amortization and interest expense with the remaining proceeds of $10 million from the cash settlement applied as a reduction of Administrative and general expenses.

In July 2016, PGE requested from the OPUC a regulatory deferral for the recovery of the revenue requirement associated with the excess capital costs for Carty. The Company requested that the OPUC delay its review of this deferral request until all legal actions with respect to this matter, including PGE’s actions against the Sureties, were resolved. As a result of the settlement described above, the Company withdrew the deferral application.

A de minimis amount of liens and claims filed for goods and services provided under third-party contracts with the Contractor remain in dispute. The Company believes the remaining claims by subcontractors are not owed by the Company and is contesting the liens and claims in the courts.

Deschutes River Alliance Clean Water Act Claims

Deschutes River Alliance v. Portland General Electric Company, U.S. District Court of the District of Oregon.

On August 12, 2016, the Deschutes River Alliance (DRA) filed a lawsuit against the Company, Deschutes River Alliance v. Portland General Electric Company, U.S. District Court of the District of Oregon, that sought injunctive and declaratory relief against PGE under the Clean Water Act (CWA) related to alleged past and continuing violations of the CWA. Specifically, DRA claimed PGE had violated certain conditions contained in PGE’s Water Quality Certification for the Pelton/Round Butte Hydroelectric Project (Project) related to dissolved oxygen, temperature, and measures of acidity or alkalinity of the water. DRA alleged the violations were related to PGE's operation of the Selective Water Withdrawal (SWW) facility at the Project.

The SWW, located above Round Butte Dam on the Deschutes River in central Oregon, is, among other things, designed to blend water from the surface of the reservoir with water near the bottom of the reservoir and was constructed and placed into service in 2010, as part of the FERC license requirements, for the purpose of restoration and enhancement of native salmon and steelhead fisheries above the Project. DRA alleged that PGE's operation of the SWW caused the above-referenced violations of the CWA, which in turn degraded the Deschutes River's fish and wildlife habitat below the Project and harmed the economic and personal interests of DRA's members and supporters.

In September 2016, PGE filed a motion to dismiss, which asserted that the CWA did not allow citizen suits of that nature, and that the FERC had jurisdiction over all licensing issues, including the alleged CWA violations. On March 27, 2017, the court denied PGE's motion to dismiss. On April 7, 2017, the U.S. District Court granted an unopposed motion filed by the Confederated Tribes of Warm Springs (CTWS) to appear in the case as a friend of the court. The CTWS shares ownership of the Project with PGE but was not initially named as a defendant.

In March and April 2018, DRA and PGE filed cross-motions for summary judgment and PGE and the CTWS filed separate motions to dismiss. At a hearing on May 9, 2018, the Judge requested that PGE file an alternative motion to dismiss, which the Company and the CTWS filed on May 16, 2018. On June 11, 2018, the court denied the motions to dismiss filed in March 2018 and held that the CTWS was a necessary party to the lawsuit. DRA thereafter joined the CTWS as a defendant.

On August 3, 2018, the Judge denied DRA's motions for partial summary judgment and granted PGE's and CTWS's cross-motions for summary judgment, ruling in favor of PGE and CTWS. The Judge found that DRA had not shown a genuine dispute of material fact sufficient to support its contention that PGE and CTWS were operating the Project in violation of the CWA, and accordingly dismissed the case.

On August 24, 2018, DRA filed a motion seeking to alter or amend the judgment of dismissal, arguing that there is a genuine dispute of fact regarding PGE's compliance with requirements under the CWA. On October 1, 2018, the Judge denied DRA's motion to alter or amend the judgment of dismissal. On October 17, 2018, DRA filed an appeal to the Ninth Circuit Court of Appeals.

The Company cannot predict the outcome of this matter or determine the likelihood of whether the outcome of this matter will result in a material loss.

10. None

11. (Reserved)

12. None

13. Changes in Officers and Directors:

    Campbell A. Henderson, Vice President, Information Technology and Chief Information Officer, retired from the Company effective January 2, 2018.

    John Kochavatr, Vice President, Information Technology and Chief Information Officer was appointed to position effective February 1, 2018.

    Carol Dillin, Vice President, Customer Strategies and Business Development resigned effective September 12, 2018.

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 2018/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	10,513,713,376	10,081,537,481
3	Construction Work in Progress (107)	200-201	346,348,706	390,550,304
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		10,860,062,082	10,472,087,785
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,948,724,140	4,663,342,841
6	Net Utility Plant (Enter Total of line 4 less 5)		5,911,337,942	5,808,744,944
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)		5,911,337,942	5,808,744,944
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		2,567,291	48,510,868
19	(Less) Accum. Prov. for Depr. and Amort. (122)		573,481	16,088,583
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	77,812,205	143,936
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)		82,427,119	83,172,108
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		2,391,252	297,009
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		164,624,386	116,035,338
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		6,714,924	8,913,582
36	Special Deposits (132-134)		16,380,586	11,418,874
37	Working Fund (135)		9,000	22,200
38	Temporary Cash Investments (136)		112,000,000	30,000,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		171,382,224	135,645,919
41	Other Accounts Receivable (143)		36,286,206	38,342,848
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		14,784,074	6,344,122
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		41,863	66,656
45	Fuel Stock (151)	227	27,662,897	24,167,931
46	Fuel Stock Expenses Undistributed (152)	227	40,377	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	49,232,592	48,363,416
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	490
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	3,120,107	2,331,408

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	3,627,267	3,988,473
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)		55,297,263	56,069,078
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		96,163,635	105,509,836
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		20,436,421	5,966,435
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		2,391,252	297,009
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)		581,220,036	464,166,015
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		9,074,103	9,948,581
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	26,054,936	1,698,256
72	Other Regulatory Assets (182.3)	232	467,226,599	535,236,011
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,708,425	2,172,803
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)		-22,139	211,312
77	Temporary Facilities (185)		0	4,597
78	Miscellaneous Deferred Debits (186)	233	13,853,327	14,082,050
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)		15,998,527	18,937,291
82	Accumulated Deferred Income Taxes (190)	234	580,219,209	606,727,109
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,114,112,987	1,189,018,010
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		7,771,295,351	7,577,964,307

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2018/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	1,215,804,775	1,210,926,574
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	18,838,837	18,838,837
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	23,113,532	23,113,532
11	Retained Earnings (215, 215.1, 216)	118-119	1,301,346,961	1,217,326,912
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-2,304	132,936
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-6,432,434	-7,906,742
16	Total Proprietary Capital (lines 2 through 15)		2,506,442,303	2,416,204,985
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,487,800,000	2,436,400,000
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	65,879	71,868
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		483,555	540,975
24	Total Long-Term Debt (lines 18 through 23)		2,487,382,324	2,435,930,893
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		46,153,665	48,648,132
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		8,626,035	8,867,943
29	Accumulated Provision for Pensions and Benefits (228.3)		418,540,512	399,235,308
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		25,170,794	1,981,970
32	Long-Term Portion of Derivative Instrument Liabilities		101,492,253	150,869,575
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		197,325,930	166,978,691
35	Total Other Noncurrent Liabilities (lines 26 through 34)		797,309,189	776,581,619
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		279,720,480	228,100,970
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		409,419	179,005
41	Customer Deposits (235)		12,628,714	13,544,300
42	Taxes Accrued (236)	262-263	17,061,108	13,866,867
43	Interest Accrued (237)		26,601,559	26,780,919
44	Dividends Declared (238)		33,647,077	31,445,355
45	Matured Long-Term Debt (239)		0	0

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)		16,891,216	16,775,837
48	Miscellaneous Current and Accrued Liabilities (242)		46,723,070	21,451,375
49	Obligations Under Capital Leases-Current (243)		2,494,467	2,572,730
50	Derivative Instrument Liabilities (244)		151,874,495	209,422,871
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		101,492,253	150,869,575
52	Derivative Instrument Liabilities - Hedges (245)		4,166,551	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		490,725,903	413,270,654
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	139,125,688	124,641,511
60	Other Regulatory Liabilities (254)	278	400,701,445	428,336,695
61	Unamortized Gain on Reaquired Debt (257)		34,221	42,273
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		802,222,298	820,571,329
64	Accum. Deferred Income Taxes-Other (283)		147,351,980	162,384,347
65	Total Deferred Credits (lines 56 through 64)		1,489,435,632	1,535,976,155
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		7,771,295,351	7,577,964,306

Schedule Page: 112   Line No.: 31   Column: c

The 2018 balance includes a $45 million deferral, including interest, of the 2018 net tax benefits due to the change in corporate tax rate under the U.S. Tax Cuts and Jobs Act (TCJA) that was enacted on 12/22/2017, which among other provisions, reduced the federal corporate tax rate from 35% to 21%. As a result of the change in corporate tax rate, PGE incurred lower income tax expense in 2018 than was estimated in setting customer prices in PGE's 2018 General Rate Case. PGE proposed to defer and refund the expected net benefits from 2017 and 2018 related to the TCJA under a deferral application filed with the OPUC on December 29, 2017. On December 4, 2018, PGE received OPUC approval to refund a total of $45 million dollars to customers for the 2017-2018 net benefits associated with the TCJA. The refund will begin amortizing in customer prices on January 1, 2019 over a two-year period. As a result, $23 million of the deferral that is expected to be refunded to customers during 2019 was reclassed to Miscellaneous Current and Accrued Liabilities (Acct 242).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	2,005,110,043	2,022,693,552		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,013,130,293	1,014,564,000		
5	Maintenance Expenses (402)	320-323	140,546,552	161,260,902		
6	Depreciation Expense (403)	336-337	295,871,290	290,673,780		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	6,887,693	6,891,509		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	58,972,528	46,134,140		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		1,337,373	-15,481,862		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		13,614,738	12,971,720		
13	(Less) Regulatory Credits (407.4)		4,661,294	2,109,466		
14	Taxes Other Than Income Taxes (408.1)	262-263	126,448,833	121,629,678		
15	Income Taxes - Federal (409.1)	262-263	12,094,601	5,389,048		
16	- Other (409.1)	262-263	22,102,339	12,084,686		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	279,571,946	506,077,684		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	294,774,017	438,525,396		
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)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		3,788,822	3,662,308		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,674,931,697	1,725,222,731		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		330,178,346	297,470,821		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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
2,005,110,043	2,022,693,552					2
						3
1,013,130,293	1,014,564,000					4
140,546,552	161,260,902					5
295,871,290	290,673,780					6
6,887,693	6,891,509					7
58,972,528	46,134,140					8
						9
1,337,373	-15,481,862					10
						11
13,614,738	12,971,720					12
4,661,294	2,109,466					13
126,448,833	121,629,678					14
12,094,601	5,389,048					15
22,102,339	12,084,686					16
279,571,946	506,077,684					17
294,774,017	438,525,396					18
						19
						20
						21
						22
						23
3,788,822	3,662,308					24
1,674,931,697	1,725,222,731					25
330,178,346	297,470,821					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		330,178,346	297,470,821		
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)		2,793,176	2,718,347		
34	(Less) Expenses of Nonutility Operations (417.1)		2,313,308	3,151,752		
35	Nonoperating Rental Income (418)		3,470,547	2,998,518		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-60,240	-81,389		
37	Interest and Dividend Income (419)		1,630,837	335,336		
38	Allowance for Other Funds Used During Construction (419.1)		10,893,676	11,726,094		
39	Miscellaneous Nonoperating Income (421)		-4,135,852	1,287,467		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		12,278,836	15,832,621		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		-20,322	20,322		
45	Donations (426.1)		2,155,569	1,871,065		
46	Life Insurance (426.2)		542,802	-2,751,122		
47	Penalties (426.3)		5,432	37,888		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		920,406	996,431		
49	Other Deductions (426.5)		3,421,545	4,217,367		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		7,025,432	4,391,951		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,472,259	1,146,107		
53	Income Taxes-Federal (409.2)	262-263	-205,745	-1,176,868		
54	Income Taxes-Other (409.2)	262-263	-72,480	-277,143		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	4,080,244	6,026,612		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	5,430,472	3,576,299		
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)		-156,194	2,142,409		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		5,409,598	9,298,261		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		122,549,959	117,516,111		
63	Amort. of Debt Disc. and Expense (428)		930,264	1,042,671		
64	Amortization of Loss on Reaquired Debt (428.1)		2,938,764	3,369,702		
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)		3,017,293	3,716,817		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		5,730,984	6,000,616		
70	Net Interest Charges (Total of lines 62 thru 69)		123,697,244	119,636,633		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		211,890,700	187,132,449		
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)		211,890,700	187,132,449		

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 2018/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		1,213,474,117	1,146,246,160
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)		211,950,940	187,213,838
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		238	-128,005,891	(119,985,881)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-128,005,891	(119,985,881)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		75,000	
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,297,494,166	1,213,474,117
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		3,852,795	3,852,795
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,852,795	3,852,795
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,301,346,961	1,217,326,912
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		132,936	214,325
50	Equity in Earnings for Year (Credit) (Account 418.1)		-60,240	(81,389)
51	(Less) Dividends Received (Debit)		75,000	
52				
53	Balance-End of Year (Total lines 49 thru 52)		-2,304	132,936

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 2018/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)	211,890,700	187,132,449
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	361,731,511	343,699,429
5	Amortization of Debt Discount	3,860,976	4,404,321
6	Amortization of Unrecovered Plant	1,337,373	-15,481,862
7	Price Risk Management	-67,851,811	57,162,858
8	Deferred Income Taxes (Net)	-16,552,299	70,002,601
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	-15,868,717	-10,937,570
11	Net (Increase) Decrease in Inventory	-4,831,522	3,194,970
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	53,735,147	2,182,425
14	Net (Increase) Decrease in Other Regulatory Assets	75,577,212	-95,530,224
15	Net Increase (Decrease) in Other Regulatory Liabilities	38,567,394	46,811,742
16	(Less) Allowance for Other Funds Used During Construction	10,893,676	11,726,094
17	(Less) Undistributed Earnings from Subsidiary Companies	-60,240	-81,389
18	Margin Deposits	-5,877,298	-6,308,474
19	Other	4,888,747	17,987,352
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	629,773,977	592,675,312
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-560,895,227	-521,932,854
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-3,944,473	-4,106,903
30	(Less) Allowance for Other Funds Used During Construction	-10,893,676	-11,726,094
31	Other Capital Activities	123,860,346	2,042,892
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-430,085,678	-512,270,771
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Sale of Property	1,347,171	
39	Investments in and Advances to Assoc. and Subsidiary Companies	-45,204,565	
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent 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 2018/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Other Investments	-2,469,336	-3,413,222
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Purchases of Trojan Decommissioning Securities	-12,105,038	-17,690,262
54	Sales of Trojan Decommissioning Securities	14,613,050	20,708,931
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-473,904,396	-512,665,324
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	75,000,000	225,000,000
62	Preferred Stock		
63	Common Stock	-2,187,650	-3,335,911
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	72,812,350	221,664,089
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-23,605,989	-150,005,989
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Debt Issue Costs		-949,780
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-125,287,800	-117,509,731
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-76,081,439	-46,801,411
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	79,788,142	33,208,577
87			
88	Cash and Cash Equivalents at Beginning of Period	38,935,782	5,727,205
89			
90	Cash and Cash Equivalents at End of period	118,723,924	38,935,782

Schedule Page: 120 Line No.: 31 Column: b

Amount primarily consists of $120 million of cash received from the Carty settlement.

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

The amount of $1.3 million represents the sale of streetlights and related equipment to the City of Hillsboro, OR.

Schedule Page: 120 Line No.: 39 Column: b

In November 2018, PGE purchased the company headquarters building complex through its wholly owned subsidiary, 121 SW Salmon Corporation.

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)	$ 8,913,582	$ 6,714,924
Working Funds (135)	22,200	9,000
Temporary Cash Investments (136)	30,000,000	112,000,000
	$ 38,935,782	$ 118,723,924
	2017	**2018**
Cash paid during the year:		
Interest	$ 115,688,306	$ 122,775,667
Allowance for borrowed funds used during construction	(6,000,616)	(5,730,984)
	$ 109,687,690	$ 117,044,683
Income Taxes	$ 18,268,023	$ 24,923,371
Non-cash investing and financing activities:		
Accrued capital additions	$ 53,364,382	$ 60,573,744
Accrued dividends payable	31,445,355	33,647,077
Assets obtained under leasing arrangements	86,417,558	23,514,053
Preliminary engineering transferred to Construction work in progress	266,487	2,124,989

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 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. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company's corporate headquarters is located in Portland, Oregon and its approximately 4,000 square mile, state-approved service area is located entirely within the State of Oregon. PGE's allocated service area includes 51 incorporated cities, of which Portland and Salem are the largest. As of December 31, 2018, PGE served approximately 885,000 retail customers with a service area population of approximately 1.9 million, comprising approximately 46% of the population of the state.

As of December 31, 2018, PGE had 2,967 employees, with 802 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 747 and 55 employees and expire March 2020 and August 2022, 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, accumulated asset retirement removal costs, and the non-service component of pension expense.

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 - 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.

For GAAP reporting, the portion of payments under capital lease obligations related to principal is recorded as a financing outflow and included in Net Cash Provided by (Used in) Financing Activities; however, the FERC Statement of Cash Flows includes such amounts on the Other line of Net Cash Provided by Operating Activities.

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.

Subsequent events

PGE has evaluated the impact of events occurring after December 31, 2018 up to February 15, 2019, the date that the Company's U.S. GAAP financial statements were issued, and has updated such evaluation for disclosure purposes through April 12, 2019. 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 $112 million as of December 31, 2018 and $30 million as of December 31, 2017.

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 eight 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 the 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 2018 or 2017.

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, 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, the Company recognizes a realized gain or loss on the derivative instrument.

Physically settled electricity and natural gas sale and purchase transactions 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 included within Other current assets in the Comparative Balance Sheet and were $16 million and $11 million as of December 31, 2018 and 2017, respectively. Letters of credit provided as collateral are not recorded on the Company's Comparative Balance Sheet and were $48 million and $31 million as of December 31, 2018 and 2017, 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, which includes natural gas, coal, and oil for use in the Company's generating plants. Periodically, the Company assesses inventory for purposes of determining that it is recorded at the lower of average cost or net realizable value.

Utility Plant

Capitalization Policy

Utility Plant is capitalized at 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 PGE'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 FERC licenses 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, PGE 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 2018 and 2017. AFDC from borrowed funds was $6 million in 2018 and 2017 and is reflected as a reduction to Interest Charges. AFDC from equity funds, included in Other Income, was $11 million in 2018 and $12 million in 2017.

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 2018 and 2017. A component of Depreciation Expense includes estimated asset retirement removal costs allowed in customer prices.

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 2015, with an order received from the OPUC in September 2017 authorizing new depreciation rates effective January 1, 2018. This study was incorporated into the Company's 2018 general rate case filed with the OPUC in 2017.

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 PGE's other classes of plant in service over their estimated average service lives, which are as follows (in years):

Generation, excluding thermal:	
Hydro	99
Wind	30
Transmission	59
Distribution	46
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 $302 million and $296 million as of December 31, 2018 and 2017, respectively, with amortization expense of $59 million in 2018 and $46 million in 2017. Future estimated amortization expense as of December 31, 2018 is as follows: $60 million in 2019; $52 million in 2020; $44 million in 2021; $38 million in 2022; and $29 million in 2023.

Marketable Securities

All of PGE's investments in marketable securities, included in the Non-qualified benefit plan trust and Nuclear decommissioning trust on the Comparative Balance Sheet, are classified as equity or trading debt securities. These securities are classified as noncurrent because they are not available for use in operations. Such 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 Miscellaneous Nonoperating Income. 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: i) prices are established by, or subject to, approval by independent third-party regulators; ii) prices are designed to recover the specific enterprise’s cost of service; and iii) 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 PGE’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. The Company 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 PGE’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: i) net variable power costs (NVPC) forecast each year and included in customer prices (baseline NVPC); and ii) actual NVPC. NVPC consists of 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 wholesale sales, which are classified as Operating Revenues in the Statement of Income.

The Company is subject to a portion of the business risk or benefit associated with the difference between actual and baseline NVPC by application of an asymmetrical deadband, which ranges from $15 million below to $30 million above baseline NVPC.

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 the given 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 9.5% for 2018 and 9.6% for 2017.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Operating Revenues in PGE’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 market-risk premiums are not available. The present value of estimated future decommissioning costs is capitalized and included in Utility Plant 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 included in 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 ARO 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. As of December 31, 2018, PGE had a net regulatory liability related to Utility plant AROs in the amount of $53 million and a net regulatory asset related to Trojan decommissioning ARO activities of $25 million. As of December 31, 2017, PGE had a net regulatory liability related to Utility plant AROs in the amount of $52 million and a net regulatory liability related to Trojan decommissioning ARO activities of $3 million. 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. Legal costs incurred in connection with loss contingencies are expensed as incurred. Loss contingencies, including environmental 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 determined, 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.

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

For additional information concerning the Company's contingencies, see Note 16, Contingencies.

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

Revenue is recognized when obligations under the terms of a contract with customers are satisfied. Generally, this satisfaction of performance obligations and transfer of control occurs and revenues are recognized as electricity is delivered to customers, including any services provided. The prices charged, and amount of consideration PGE receives in exchange for its goods and services provided, are regulated by the Public Utility Commission of Oregon (OPUC) or the Federal Energy Regulatory Commission (FERC). PGE recognizes revenue through the following steps: i) identifying the contract with the customer; ii) identifying the performance obligations in the contract; iii) determining the transaction price; iv) allocating the transaction price to the performance obligations; and v) recognizing revenue when or as each performance obligation is satisfied.

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 Revenues and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $45 million in 2018 and $43 million in 2017.

Retail revenue is billed based on monthly meter readings taken at various cycle dates throughout the month. At the end of each month, PGE estimates the revenue earned from energy deliveries that has not yet been billed to customers. This amount, which is classified as Unbilled revenues in the Company's Comparative Balance Sheet, is calculated based on actual net retail system load each month, the number of days from the last meter read date through the last day of the month, and current customer prices.

As a rate-regulated utility, PGE, in certain situations, 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. For additional information concerning the Company's Stock-Based Compensation, see Note 13, Stock-Based Compensation Expense.

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 would be established to reduce deferred tax assets to the "more likely than not" amount expected to be realized in future tax returns.

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 Interest Charges and Miscellaneous Nonoperating Income, respectively, in the Statement of Income.

Recent Accounting Pronouncements

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2016-02, *Leases (Topic 842)*, which supersedes the current lease accounting requirements for lessees and lessors within Topic 840, Leases. Pursuant to the new standard, lessees will be required to recognize all leases, including operating leases, on the Comparative Balance Sheet and record corresponding right-of-use (ROU) assets and lease liabilities. Accounting for lessors is substantially unchanged from current accounting principles. Lessees will be required to classify leases as either finance leases or operating leases. Initial Comparative Balance Sheet measurement is similar for both types of leases; however, expense recognition and amortization of right-of-use assets will differ.

The new standard provides optional practical expedients in transition. PGE does not expect to elect the 'package of practical expedients' that would allow the Company to carryforward the historical lease classification, but instead, PGE has elected to reassess all arrangements that may contain a lease and their resulting lease classification. PGE is substantially complete with this reassessment, and as a result, certain arrangements will no longer be considered a lease under Topic 842. PGE does not expect to elect the use-of-hindsight practical expedient. The new standard also provides practical expedients for an entity's ongoing accounting. PGE currently expects to elect the short-term lease recognition exemption for all leases that qualify, which means leases with initial terms of 12 months or less will not be recorded on the Comparative Balance Sheet.

As issued, ASU 2016-02 requires transition under a modified retrospective basis as of the beginning of the earliest comparative period presented; however in July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842) Targeted Improvements*, which amends ASU 2016-02 to provide entities an optional transition practical expedient that allows companies to adopt the new standard with a cumulative effect adjustment as of the beginning of the year of adoption with prior year comparative financial information and disclosures remaining as previously reported. PGE plans to elect this practical expedient and does not expect a material adjustment to beginning retained earnings. In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842) Land Easement Practical Expedient for Transition to Topic 842*, which amends ASU 2016-02 to provide entities an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840. PGE plans to elect this practical expedient, and after adoption will evaluate new or modified land easements under Topic 842. The provisions of these pronouncements are effective for calendar year-end, public entities on January 1, 2019. Early adoption is permitted, but the Company does not plan to early adopt.

The Company does not expect this standard to have a material effect on the Company's financial position. While PGE continues to assess all of the effects of adoption, PGE currently anticipates the most significant effects as a lessee relate to: i) the recognition of new ROU assets and lease liabilities on its Comparative Balance Sheet, which are expected to range from $40 million to $50 million; ii) the derecognition of existing build-to-suit assets and liabilities of approximately $131 million that are no longer considered to meet build-to-suit criteria under Topic 842 and will not be recognized on the Company's Comparative Balance Sheet until commencement, which is expected in the spring of 2019; iii) the derecognition of approximately $50 million in net lease assets and liabilities related to existing capital leases that do not meet the definition of a lease under the new standard; and iv) providing new disclosures regarding key information about leasing arrangements. The Company does not expect this standard to have a material impact to its results of operations, cash flows, or liquidity measures, such as debt covenant ratios.

In the fourth quarter of 2018, the Company's wholly-owned subsidiary, 121 SW Salmon Street Corporation, purchased the corporate headquarters complex and leases the complex to the Company. The Company is currently assessing the impact of the related party lease on its regulatory basis financial statements.

In February 2018, the FASB issued ASU 2018-02 *Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* (ASU 2018-02). ASU 2018-02 allows for a reclassification from accumulated other comprehensive income to retained earnings for the stranded tax effects resulting from the United States Tax Cuts and Jobs Act of 2017 (TCJA). The amendments only relate to the reclassification of the income tax effects of the TCJA, and therefore the underlying guidance that requires that the effect of a change in tax laws or rates be included in income from continuing operations is not affected. For calendar year-end entities, the update will be effective for annual periods beginning January 1, 2019, and interim periods within those fiscal years. Early adoption of the amendments is permitted, including adoption in any interim period. PGE has determined that ASU 2018-02 will not have a material impact on its financial position and does not plan to early adopt the standard.

In August 2018, the FASB issued ASU 2018-13 *Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement*. ASU 2018-13 amends Topic 820 to add, remove, and clarify disclosure requirements related to fair value measurement disclosure. For calendar year-end entities, the update will be effective for annual periods beginning January 1, 2020, and interim periods within those fiscal years. Early adoption of the amendments is permitted, including adoption in an interim period. As the standard relates only to disclosures, PGE does not expect the adoption to have a material impact on the financial statements and is still evaluating if it will early adopt.

In August 2018, the FASB issued ASU 2018-14 *Compensation—Retirement Benefits—Defined Benefit Plans—General (Subtopic 715-20): Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans*. ASU 2018-14 amends Topic 715 to add, remove, and clarify disclosure requirements related to defined benefit pension and other postretirement plans. For calendar year-end entities, the update will be effective for annual periods beginning on January 1, 2021, early adoption is permitted. As the standard relates only to disclosures, PGE does not expect the adoption to have a material impact on the financial statements and is still evaluating whether it will early adopt.

In August 2018, the FASB issued ASU 2018-15 *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*, to provide guidance on implementation costs incurred in a cloud computing arrangement that is a service contract. ASU 2018-15 aligns the accounting for such costs with the guidance on capitalizing costs associated with developing or obtaining internal-use software. For calendar year-end entities, the update will be effective for annual periods beginning on January 1, 2020, early adoption is permitted, including adoption in an interim period. The amendments in this update should be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. PGE is in the process of evaluating potential impacts of these amendments, and whether it will early adopt.

Recently Adopted Accounting Pronouncements

On January 1, 2018, PGE adopted ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which created Topic 606 and superseded the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. The Company applied the modified retrospective transition method to its revenue contracts not yet completed as of January 1, 2018. As a result, amounts previously recorded prior to January 1, 2018 have not been retrospectively restated and are reported in accordance with historical accounting under Topic 605, while revenues for 2018 have been presented under Topic 606.

PGE's transition to the new revenue standard did not result in a material adjustment to opening retained earnings and the Company expects the adoption of the new standard to have an immaterial impact to its results of operations on an ongoing basis. Certain elements of Topic 606 were not considered applicable for FERC reporting, primarily related to the separate presentation of alternative revenue programs and the addition of disaggregated revenue disclosures.

On January 1, 2018, PGE adopted ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments*, which provided guidance for eight specific cash flow issues where there had historically been diversity in practice. The eight areas of the cash flow impacted were debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance (COLI) policies, distributions received from equity method investments, beneficial interest in securitization transactions, and separately identifiable cash flows and application of the predominance principal. The standard did not have a material impact to PGE for any other area for which guidance was provided on the statement of cash flows. The implementation of ASU 2016-15 has had an immaterial impact on PGE's financial position and results of operations.

NOTE 3: COMPARATIVE BALANCE SHEET COMPONENTS

Accumulated Provision for Uncollectible Accounts

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

	Years Ended December 31,	
	2018	**2017**
Balance as of beginning of year	$ 6	$ 6
Increase in provision	14	6
Amounts written off, less recoveries	(5)	(6)
Balance as of end of year	$ 15	$ 6

Trust Accounts

PGE maintains the following trust accounts, 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 (NDT) includes amounts collected from customers, less qualified expenditures, plus any realized and unrealized gains and losses on the investments held therein.

Non-qualified benefit plan trust—Reflects assets held in trust to cover the obligations of PGE's non-qualified benefit plans (NQBP) 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	
	2018	**2017**	**2018**	**2017**
Cash equivalents	$ 7	$ 25	$ 2	$ 1
Marketable securities, at fair value:				
Equity securities	—	—	6	7
Debt securities	35	17	1	1
Insurance contracts, at cash surrender value	—	—	27	28
	$ 42	$ 42	$ 36	$ 37

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, 2018 and 2017. The Company then classifies these financial assets and liabilities based on a fair value hierarchy that is applied to prioritize the inputs to the valuation techniques used to measure fair value. The three levels of the fair value hierarchy 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 measurement date.

Level 2 Pricing inputs include those that are directly or indirectly observable in the marketplace as of the measurement 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. Assets measured at fair value using net asset value (NAV) as a practical expedient are not categorized in the fair value hierarchy. These assets are listed in the totals of the fair value hierarchy to permit the reconciliation to amounts presented in the financial statements.

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, 2018 and 2017, except those 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, 2018				
	Level 1	Level 2	Level 3	Other(2)	Total
Assets:					
Temporary cash investments	$ 112	$ —	$ —	$ —	$ 112
Nuclear decommissioning trust: (1)					
Debt securities:					
Domestic government	7	18	—	—	25
Corporate credit	—	10	—	—	10
Money market funds measured at NAV (2)	—	—	—	7	7
Non-qualified benefit plan trust: (3)					
Money market funds	2	—	—	—	2
Equity securities—domestic	6	—	—	—	6
Debt securities—domestic government	1	—	—	—	1
Price risk management activities: (1) (4)					
Electricity	—	9	3	—	12
Natural gas	—	8	—	—	8
	$ 128	$ 45	$ 3	$ 7	$ 183
Liabilities:					
Interest rate swap derivatives	$ —	$ 4	$ —	$ —	4
Price risk management activities: (1) (4)					
Electricity	—	10	84	—	94
Natural gas	—	51	7	—	58
	$ —	$ 65	$ 91	$ —	$ 156

(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) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $27 million, which are recorded at cash surrender value.
(4) For further information regarding price risk management derivatives, see Note 5, Risk Management.

	As of December 31, 2017				
	Level 1	Level 2	Level 3	Other(2)	Total
Assets:					
Temporary cash investments	$ 30	$ —	$ —	$ —	$ 30
Nuclear decommissioning trust: (1)					
Debt securities:					
Domestic government	$ 4	$ 7	$ —	$ —	$ 11
Corporate credit	—	6	—	—	6
Money market funds measured at NAV (2)	—	—	—	25	25
Non-qualified benefit plan trust: (3)					
Money market funds	1	—	—	—	1
Equity securities—domestic	7	—	—	—	7
Debt securities—domestic government	1	—	—	—	1
Price risk management activities: (1) (4)					
Electricity	—	3	—	—	3
Natural gas	—	3	—	—	3
	$ 43	$ 19	$ —	$ 25	$ 87
Liabilities:					
Price risk management activities: (1) (4)					
Electricity	$ —	$ 5	$ 130	$ —	$ 135
Natural gas	—	66	9	—	75
	$ —	$ 71	$ 139	$ —	$ 210

(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) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $28 million, which are recorded at cash surrender value.
(4) For further information regarding price risk management derivatives, see Note 5, Risk Management.

Temporary Cash Investments are highly liquid investments with maturities of three months or less at the date of acquisition and primarily consist of money market funds. Such funds seek to maintain a stable net asset value and are comprised of short-term, government funds. Policies of such funds require that the weighted average maturity of the fund's securities holdings do not exceed 90 days and investors have the ability to redeem the fund's shares daily at its respective net asset value. These temporary cash investments 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 measurement date. Principal markets for money market fund prices include published exchanges such as NASDAQ and the New York Stock Exchange.

Assets held in the NDT and NQBP 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:

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 measurement 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 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 measurement date. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange (NYSE).

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. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value. Redemption is permitted daily without written notice.

The NQBP trust is invested in exchange traded government money market funds and is classified as Level 1 in the fair value hierarchy due to the availability of quoted prices in published exchanges such as NASDAQ and the NYSE. The money market fund in the NDT is valued at NAV as a practical expedient and is not included in the fair value hierarchy.

Liabilities from interest rate swap derivatives are recorded at fair value in PGE's Comparative Balance Sheet and consist of forward starting interest rate swap lock agreements to hedge a portion of its interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities. To establish fair values for interest rate swap derivatives, the Company uses forward market curves for interest rates for the term of the swaps and discounts the cash flows back to present value using an appropriate discount rate. The discount rate is calculated by third party brokers according to the terms of the swap derivatives and evaluated by the Company for reasonableness. Future cash flows of the interest rate swap derivatives are equal to the fixed interest rate in the swap compared to the floating market interest rate multiplied by the notional amount for each period.

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 to reduce volatility in NVPC for the Company's retail customers. For additional information regarding these assets and liabilities, see Note 5, 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, 2018:							
Electricity physical forward	$ 3	$ 84	Discounted cash flow	Electricity forward price (per MWh)	$ 14.60	$ 69.00	$ 45.00
Natural gas financial swaps	—	7	Discounted cash flow	Natural gas forward price (per Dth)	0.95	4.64	1.82
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	20.75	35.46	28.63
	$ 3	$ 91					
As of December 31, 2017:							
Electricity physical forward	$ —	$ 130	Discounted cash flow	Electricity forward price (per MWh)	$ 7.79	$ 41.23	$ 30.95
Natural gas financial swaps	—	9	Discounted cash flow	Natural gas forward price (per Dth)	1.26	2.92	1.90
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	7.79	29.74	21.74
	$ —	$ 139					

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, PGE 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 quarterly 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,	
	2018	2017
Net liabilities from price risk management activities as of beginning of year	$ 139	$ 119
Net realized and unrealized losses *	(40)	35
Net transfers out of Level 3 to Level 2	(11)	(15)
Net liabilities from price risk management activities as of end of year	$ 88	$ 139
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 32	$ 41

* Includes $8 million in net realized losses in 2018 and $6 million in 2017.

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, 2018 and 2017, there were no 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.

As of December 31, 2018, the carrying amount of PGE's long-term debt was $2,488 million and its estimated aggregate fair value was $2,760 million, all of which is classified as Level 2 in the fair value hierarchy. As of December 31, 2017, the carrying amount of PGE's long-term debt was $2,436 million, with an estimated aggregate fair value of $2,829 million, all of which was classified as Level 2 in the fair value hierarchy.

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

NOTE 5: RISK MANAGEMENT

Price Risk Management

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

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign exchange rate risk in order to manage volatility in NVPC for its retail customers. Such derivative instruments, recorded at fair value on the Comparative Balance Sheet, may include forward, futures, swap, and option contracts for electricity, natural gas, and foreign currency, with changes in fair value recorded in the Statement of Income. In accordance with ratemaking and cost recovery processes authorized by the OPUC, the Company 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. The Company 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,	
	2018	**2017**
Current assets:		
Commodity contracts:		
Electricity	$ 11	$ 3
Natural gas	7	3
Total current derivative assets	18	6
Noncurrent assets:		
Commodity contracts:		
Electricity	1	—
Natural gas	1	—
Total noncurrent derivative assets	2	—
Total derivative assets not designated as hedging instruments	$ 20	$ 6
Total derivative assets	$ 20	$ 6
Current liabilities:		
Commodity contracts:		
Electricity	$ 16	$ 13
Natural gas	35	46
Total current derivative liabilities	51	59
Noncurrent liabilities:		
Commodity contracts:		
Electricity	78	122
Natural gas	23	29
Total noncurrent derivative liabilities	101	151
Total derivative liabilities not designated as hedging instruments	$ 152	$ 210
Total derivative liabilities	$ 152	$ 210

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,					
	2018			2017		
Commodity contracts:						
Electricity		5	MWh		7	MWh
Natural gas		123	Dth		114	Dth
Foreign currency exchange	$	18	Canadian	$	21	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, such agreements provide for the net settlement of all related contractual obligations with a given 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, 2018, and 2017, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $88 million and $136 million, respectively, for which PGE posted collateral of $11 million for 2018 and 2017, which consisted entirely of letters of credit. As of December 31, 2018, of the gross amounts included, $84 million was for electricity and $4 million was for natural gas compared to $130 million for electricity and $6 million for natural gas recognized as of December 31, 2017.

Net realized and unrealized losses (gains) 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,			
	2018		2017	
Commodity contracts:				
Electricity	$	(34)	$	41
Natural Gas		21		85
Foreign currency exchange		1		(1)

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the Statement of Income by the effects of regulatory accounting. Of the net amounts recognized in Net income, net gains of $18 million and net losses of $82 million for the years ended December 31, 2018 and 2017, 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, 2018 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2019	2020	2021	2022	2023	Thereafter	Total
Commodity contracts:							
Electricity	$ 4	$ 6	$ 6	$ 6	$ 6	$ 55	$ 83
Natural gas	28	14	6	1	—	—	49
Net unrealized loss	$ 32	$ 20	$ 12	$ 7	$ 6	$ 55	$ 132

PGE's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and S&P Global Ratings (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, 2018 was $144 million, for which the Company had posted $48 million in collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2018, the cash requirement to either post as collateral or settle the instruments immediately would have been $136 million. As of December 31, 2018, PGE had no posted cash collateral for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivative instruments 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,	
	2018	**2017**
Assets from price risk management activities:		
Counterparty A	42 %	39 %
Counterparty B	15	—
Counterparty C	5	12
	62 %	51 %
Liabilities from price risk management activities:		
Counterparty D	56 %	62 %
	56 %	62 %

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.

Interest Rate Risk

PGE has used two forward starting interest rate swap lock agreements to hedge a portion of its interest rate risk associated with anticipated issuances of fixed-rate, long-term debt securities. These derivatives were designated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance.

The notional amount of the interest rate swaps is $170 million with a mandatory cash settlement date in January 2019. Upon settlement of interest rate swap derivatives, the cash payments made or received are recorded as a regulatory asset or liability and are subsequently amortized as a component of interest expense over the life of the associated debt. Such amounts are also included as a component of cost of debt for ratemaking purposes.

PGE is required to make cash payments to settle the interest rate swap derivatives when the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, PGE receives cash to settle its interest rate swap derivatives when prevailing market rates at the time of settlement exceed the fixed swap rates. Until settlement, the interest rate swaps are carried at fair value as a derivative asset or liability with the corresponding offset recorded as either a regulatory liability or regulatory asset, respectively. The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swap derivatives outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. As of December 31, 2018, the fair value of the interest rate swaps was a $4 million loss, which is recorded in Derivative Instrument Liabilities - Hedges on the Company's Comparative Balance Sheet.

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):

	Remaining Amortization Period	As of December 31, 2018 Total	As of December 31, 2017 Total
Regulatory assets:			
Price risk management	2035	$ 131	$ 203
Pension and other postretirement plans	(1)	222	218
Deferred income taxes	(3)	50	56
Other	Various	64	58
Total regulatory assets		$ 467	$ 535
Regulatory liabilities:			
Deferred income taxes	(3)	$ 317	$ 332
Asset retirement obligations	(2)	53	52
Other	Various	31	44
Total regulatory liabilities		$ 401	$ 428

(1) Recovery expected over the average service life of employees.
(2) Recovery or refund expected over the estimated lives of the net balance and treated as a reduction to rate base.
(3) Will be returned to customers using the average rate assumption method over the average life of the underlying assets and treated as a reduction to rate base.

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, 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 pension and postretirement benefit costs. For further information, see Note 10, Employee Benefits.

Deferred income taxes represents income tax benefits primarily from property-related timing differences that previously flowed to customers and will be included in customer prices when the temporary differences reverse. In 2017, the net regulatory liability was increased by $357 million as the Company deferred the impact of remeasuring accumulated deferred income taxes (ADIT) pursuant to the enactment of the Tax Cuts and Jobs Act (the TCJA) on December 22, 2017. Substantially all of the amounts deferred are subject to tax normalization rules that require that the impact to the results of operations of amortizing the excess deferred income tax balance cannot occur more rapidly than would have occurred before the change in tax law. The Company uses the average rate assumption method to account for the refund to customers. For further information, see Note 11, Income Taxes. On December 4, 2018, the OPUC approved PGE's application for deferral of 2018 net benefits associated with the U.S. Tax Reconciliation Act, docketed in UM 1920, for the 12-month period beginning December 31, 2017, at an amount of $45 million.

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.

Asset retirement obligations represents 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,	
	2018	**2017**
Trojan decommissioning activities	$ 68	$ 45
Utility plant	112	109
Non-utility property	17	13
Asset retirement obligations	$ 197	$ 167

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. The NRC has mandated an increase in staffing for the next 16 years that has led to an increase in the Trojan ARO by $23 million in the first quarter of 2018. The Company also recorded accretion of $4 million and a reduction of $4 million due to settled liabilities.

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 reimbursement for damages incurred through 2009.

A trial before the U.S. Court of Federal Claims concluded in 2012, with the Court issuing a judgment awarding certain damages to the Plaintiffs. The settlement agreement also provides for a process to submit claims for allowable costs for the periods subsequent to 2009, including an extension to cover costs through 2019. Pursuant to this process, the USDOE has reimbursed the Plaintiffs $89 million for costs incurred through 2017 resulting from USDOE delays in accepting spent nuclear fuel.

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 2018, the Company recorded an overall increase in utility AROs of $3 million, with the change comprised of accretion of $4 million, and a reduction of $1 million due to settled liabilities.

Non-utility property primarily represents AROs that have been recognized for portions of unregulated properties leased to third parties. The Company recorded a revision in non-utility AROs of $4 million.

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

	Years Ended December 31,	
	2018	2017
Balance as of beginning of year	$ 167	$ 161
Liabilities incurred	—	2
Liabilities settled	(5)	(3)
Accretion expense	8	7
Revisions in estimated cash flows	27	—
Balance as of end of year	$ 197	$ 167

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 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 NDT.

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, 2018, PGE had a $500 million revolving credit facility scheduled to expire in November 2021. On January 16, 2019 PGE executed an amendment to the credit facility extending the termination date to November 14, 2022 and allowing for unlimited extension requests, provided that lenders with a pro-rata share of more than 50%, approve the extension request. 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 applicable credit facility. The revolving credit facility contains a provision that 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 65.0% of total capitalization. As of December 31, 2018, PGE was in compliance with this covenant with a 51.5% 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 revolving 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 revolving credit facility, as of December 31, 2018, PGE had no borrowings outstanding and there were no commercial paper or letters of credit issued. As a result, as of December 31, 2018, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities that provide capacity up to a total of $220 million 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, $84 million were issued, as of December 31, 2018. Letters of credit issued are not reflected on the Company's Comparative Balance Sheet.

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, 2020.

The Company had no short-term borrowings during 2018 or 2017.

NOTE 9: LONG-TERM DEBT

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

	As of December 31,	
	2018	2017
First Mortgage Bonds, rates range from 2.51% to 9.31%, with a weighted average rate of 5.01% in 2018 and 5.03% in 2017, due at various dates through 2048	$ 2,390	$ 2,315
Pollution Control Revenue Bonds, 5% rate, due 2033	119	142
Pollution Control Revenue Bonds owned by PGE	(21)	(21)
Total long-term debt	$ 2,488	$ 2,436

First Mortgage Bonds—During December 2018, the Company issued a total of $75 million at an interest rate of 4.47%, and a maturity of 2048.

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.

Pollution Control Revenue Bonds—The Company has the option to remarket through 2033 the $21 million of Pollution Control Revenue Bonds (PCBs) held by PGE as of December 31, 2018. 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. The Company repaid $24 million of Pollution Control Revenue Bonds that were early redeemed in October 2018.

As of December 31, 2018, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2019	$ 300
2020	—
2021	160
2022	—
2023	—
Thereafter	2,028
	$ 2,488

NOTE 10: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

Defined Benefit Pension Plan—PGE sponsors a non-contributory defined benefit pension plan, which 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 that are reviewed annually and updated as appropriate.

PGE contributed $9 million to the pension plan in 2018 and $2 million in 2017. PGE does not expect to contribute to the pension plan in 2019.

Other Postretirement Benefits—PGE has non-contributory postretirement health and life insurance plans, as well as health reimbursement arrangements (HRAs) for its employees (collectively, “Other Postretirement Benefits” in the following tables). Participants 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 responsible for 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 that are reviewed annually by PGE and updated as appropriate, with measurement dates of December 31.

Non-Qualified Benefit Plan—The 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 includes pension make-up benefits for employees that participate in the unfunded Management Deferred Compensation Plan (MDCP). Investments in the NQBP trust, consisting of trust-owned life insurance policies and marketable securities, provide funding for the future requirements of these plans. The assets of such trust 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 equity or trading debt securities and recorded at fair value. The measurement date for the NQBP is December 31.

Other NQBP—In addition to the NQBP 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 NQBP trust that 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):

	2018			**2017**		
	NQBP	**Other NQBP**	**Total**	**NQBP**	**Other NQBP**	**Total**
Non-qualified benefit plan trust	$ 16	$ 20	$ 36	$ 17	$ 20	$ 37
Non-qualified benefit plan liabilities	24	81	105	27	81	108

See “*Trust Accounts*” in Note 3, Comparative Balance Sheet Components, for information on the NQBP trust.

Investment Policy and Asset Allocation—The Board of Directors of PGE appoints an Investment Committee, which is comprised of certain members of management from the Company, and establishes the Company’s asset allocation. The Investment Committee is then responsible for implementation of the asset allocation and oversight of the benefit plan investments. 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. Asset classes are regularly rebalanced to ensure asset allocations remain within prescribed parameters.

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

	As of December 31,			
	2018		2017	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	65%	67%	68%	67%
Debt securities	35	33	32	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	58%	59%	63%	62%
Debt securities	42	41	37	38
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	16%	13%	18%	12%
Debt securities	10	13	6	12
Insurance contracts	74	74	76	76
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 NQBP, 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 NQBP, 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.

Assets measured at NAV as a practical expedient are not categorized in the fair value hierarchy. These assets are listed in the totals of the fair value hierarchy to permit the reconciliation to amounts presented in the financial statements.

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	Other *	Total
As of December 31, 2018:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 67	$ —	$ —	$ —	$ 67
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	463	463
Private equity funds	—	—	—	11	11

	$ 67	$ —	$ —	$ 479	$ 546
Other Postretirement Benefit Plans assets:					
Money market funds	$ 3	$ —	$ —	$ —	$ 3
Equity securities:					
Domestic	—	3	—	—	3
International	8	—	—	—	8
Debt securities—Domestic government	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	4	4
Collective trust funds	—	—	—	7	7
	$ 11	$ 8	$ —	$ 11	$ 30
As of December 31, 2017:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 83	$ —	$ —	$ —	$ 83
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	528	528
Private equity funds	—	—	—	13	13
	$ 83	$ —	$ —	$ 546	$ 629
Other Postretirement Benefit Plans assets:					
Money market funds	$ 3	$ —	$ —	$ —	$ 3
Equity securities:					
Domestic	—	3	—	—	3
International	10	—	—	—	10
Debt securities—Domestic government	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	4	4
Collective trust funds	—	—	—	8	8
	$ 13	$ 8	$ —	$ 12	$ 33

* Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.

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 discussion provides information regarding the methods used in valuation of the various asset class 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, or certificates of deposit. Some of the money market funds held in the trusts are classified as Level 1 instruments as pricing inputs are based on unadjusted prices in an active market. The remaining money market funds are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

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 separately managed accounts are classified as Level 2 securities due to pricing inputs that are directly or indirectly observable in the marketplace.

Collective trust funds—Domestic and international mutual fund assets included in commingled trusts or separately managed accounts are valued at NAV as a practical expedient and not included in the fair value hierarchy.

Debt securities, including municipal debt and corporate credit securities, mortgage-backed securities, and asset-backed securities included in commingled trusts are valued at NAV as a practical expedient and not included in the fair value hierarchy.

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, partnerships, joint ventures, venture capital, buyout, and special situations. Private equity investments are valued at NAV as a practical expedient.

The following tables provide certain information with respect to the Company's defined benefit pension plan, other postretirement benefits, and NQBP as of and for the years ended December 31, 2018 and 2017. 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	
	2018	**2017**	**2018**	**2017**	**2018**	**2017**
Benefit obligation:						
As of January 1	$ 869	$ 797	$ 78	$ 73	$ 27	$ 27
Service cost	19	17	2	2	—	—
Interest cost	32	33	3	3	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial loss (gain)	(67)	60	(7)	3	(1)	1
Contractual termination benefits	—	—	—	1	—	—
Benefit payments	(39)	(36)	(6)	(6)	(3)	(2)
Administrative expenses	(3)	(2)	—	—	—	—
As of December 31	$ 811	$ 869	$ 72	$ 78	$ 24	$ 27
Fair value of plan assets:						
As of January 1	$ 629	$ 559	$ 33	$ 30	$ 17	$ 16
Actual return on plan assets	(50)	106	(2)	4	(1)	1
Company contributions	9	2	3	3	3	2
Participants' contributions	—	—	2	2	—	—
Benefit payments	(39)	(36)	(6)	(6)	(3)	(2)
Administrative expenses	(3)	(2)	—	—	—	—
As of December 31	$ 546	$ 629	$ 30	$ 33	$ 16	$ 17
Unfunded position as of December 31	$ (265)	$ (240)	$ (42)	$ (45)	$ (8)	$ (10)
Accumulated benefit plan obligation as of December 31	$ 734	$ 778	N/A	N/A	$ 24	$ 27

Classification in Comparative Balance Sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 16	$ 17
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(265)	(240)	(42)	(45)	(22)	(25)
Net liability	$ (265)	$ (240)	$ (42)	$ (45)	$ (8)	$ (10)
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ 25	$ (4)	$ (4)	$ —	$ (1)	$ 1
Amortization of net actuarial loss	(17)	(13)	—	—	(1)	(1)
	$ 8	$ (17)	$ (4)	$ —	$ (2)	$ —
Amounts included in AOCL*:						
Net actuarial loss (gain)	$ 226	$ 218	$ (4)	$ (1)	$ 11	$ 13
Prior service cost	—	—	—	—	—	—
	$ 226	$ 218	$ (4)	$ (1)	$ 11	$ 13
Assumptions used:						
Discount rate for benefit obligation	4.25 %	3.65 %	4.10 %- 4.26 %	3.42 %- 3.70 %	4.25 %	3.65 %
Discount rate for benefit cost	3.65 %	4.17 %	3.42 %- 3.70 %	3.75 %- 4.23 %	3.65 %	4.17 %
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 cost	7.00 %	7.50 %	6.20 %	6.26 %	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	
	2018	**2017**	**2018**	**2017**	**2018**	**2017**
Service cost	$ 19	$ 17	$ 2	$ 2	$ —	$ —
Interest cost on benefit obligation	32	33	3	3	1	1
Expected return on plan assets	(42)	(42)	(1)	(2)	—	—
Amortization of prior service cost	—	—	—	—	—	—
Amortization of net actuarial loss	17	13	—	—	1	1
Net periodic benefit cost	$ 26	$ 21	$ 4	$ 3	$ 2	$ 2

The portion of non-service costs attributable to expense related to the pension and other postretirement benefit plans, is classified as Administrative and General Expenses on the Company's Statement of Income. PGE estimates that $11 million will be amortized from AOCL into net periodic benefit cost in 2019, consisting of a net actuarial loss of $10 million for pension benefits and $1 million for non-qualified 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					
	2019	**2020**	**2021**	**2022**	**2023**	**2024 - 2028**
Defined benefit pension plan	$ 41	$ 42	$ 44	$ 45	$ 45	$ 238
Other postretirement benefits	5	5	5	5	6	22
Non-qualified benefit plans	2	2	2	2	2	10
Total	$ 48	$ 49	$ 51	$ 52	$ 53	$ 270

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 2018, 6.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2019 and 2020, then decreasing 0.25% per year thereafter, reaching 5.0% in 2026; and
- For 2017, 6.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2018, decreasing to 6.0% in 2019, then decreasing 0.25% per year thereafter, reaching 5.0% in 2023.

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 $23 million in 2018 and $21 million in 2017.

NOTE 11: INCOME TAXES

On December 22, 2017, the TCJA was enacted and signed into law with substantially all of the provisions of the TCJA having an effective date of January 1, 2018. Among other provisions, the reduction of the federal corporate tax rate from 35% to 21%, which required the Company to remeasure its existing deferred income tax balances as of December 31, 2017, had the most impact on PGE's financial condition.

As a result, the Company remeasured its accumulated deferred tax assets in FERC account 190 and recorded a regulatory asset in FERC account 182.3 and remeasured its accumulated deferred tax liabilities in FERC accounts 282 and 283 and recorded a regulatory liability in FERC account 254. These deficient and excess deferred tax items relate primarily to Utility Plant and are deemed "protected" and subject to tax normalization rules that require the benefits to be passed on to customers through future prices over the remaining useful life of the underlying assets to which the deferred income taxes relate. The protected balances in FERC accounts 182.3 and 254 as of December 31, 2018 were $8 million and $317 million, respectively. The protected balances in FERC accounts 182.3 and 254 as of December 31, 2017 were $9 million and $332 million, respectively. These deficient and excess accumulated deferred tax assets and liabilities will be reversed over time using the average rate assumption method (ARAM) and will be recorded to FERC accounts 410.1 and 411.1, respectively. Such reversal was included in customer prices per the Company's 2019 General Rate Case. The reversal pursuant to ARAM for 2018 was recorded to 410.1 and 411.1 of $1 million and $10 million, respectively.

On December 4, 2018, PGE received OPUC approval to refund a total of $45 million dollars to customers for the 2017-2018 net benefits associated with the TCJA, which includes the 2018 overcollection as well as the unprotected excess deferred income tax. The $45 million refund was recorded to a regulatory liability in FERC account 229. The refund began amortizing in customer prices on January 1, 2019 over a two-year period.

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

	Years Ended December 31,	
	2018	**2017**
Current:		
Federal	$ 12	$ 4
State and local	22	12
	34	16
Deferred:		
Federal	(15)	61
State and local	(2)	9
	(17)	70
Income tax expense	$ 17	$ 86

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,	
	2018	**2017**
Federal statutory tax rate	21.0%	35.0%
Federal tax credits[1]	(16.7)	(14.0)
Change in federal tax law[2]	—	6.1
State and local taxes, net of federal tax benefit	6.5	5.0
Flow through depreciation and cost basis differences	1.5	1.5
Excess deferred tax reversal[3]	(4.1)	—
Other	(0.8)	(2.1)
Effective tax rate	7.4%	31.5%

(1) Federal tax credits consist primarily of production tax credits (PTCs) earned from Company-owned wind-powered generating facilities. The federal PTCs are earned based on a per-kilowatt hour rate, and as a result, the annual amount of PTCs earned will vary based on weather conditions and availability of the facilities. The PTCs are generated for 10 years from the corresponding facilities' in-service dates. PGE's PTC generation ended or will end at various dates between 2017 and 2024.

(2) For the year ended December 31, 2017, includes a $17 million increase to Income tax expense related to the remeasurement of deferred income taxes as a result of the enacted tax rate change under the TCJA.

(3) The majority of excess ADIT related to remeasurement under the TCJA is subject to Internal Revenue Service (IRS) normalization rules and will be reversed over the remaining regulatory life of the assets using the ARAM.

Accumulated Deferred Income Tax Assets and Liabilities consist of the following (in millions):

	As of December 31,	
	2018	2017
Accumulated Deferred Income Tax Assets		
Employee benefits	$ 134	$ 128
Price risk management	42	58
Regulatory liabilities	26	14
Tax credits	52	50
Depreciation and amortization	304	340
Other	22	17
Total Deferred Income Tax Assets	580	607
Accumulated Deferred Income Tax Liabilities		
Depreciation and amortization	815	835
Regulatory assets	116	133
Price Risk Management	6	2
Employee benefits	—	1
Other	12	12
Total deferred income tax liabilities	949	983
Accumulated Deferred Income Tax Liability, net	$ 369	$ 376

As of December 31, 2018, PGE has federal credit carryforwards of $52 million, consisting of PTCs, which will expire at various dates through 2038. PGE has analyzed the provisions of the TCJA and its effects on the Company's deferred income tax assets, and PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2018 and 2017 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2018, and 2017, PGE had no unrecognized tax benefits.

PGE and its subsidiaries file a federal income tax return, income tax returns in the states of Oregon, California, and Montana, and returns in certain local jurisdictions. The 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.

NOTE 12: EQUITY-BASED PLANS

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP) under which a total of 625,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock (based on fair value on the purchase date) or 1,500 shares, whichever is less. Two, six-month offering periods occur annually, January 1 through June 30 and July 1 through December 31, during which eligible employees may contribute toward the purchase of shares of PGE common stock. Purchases occur the last day of the offering period, at a price equal to 95% of the fair value of the stock on the purchase date. As of December 31, 2018, there were 306,175 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, 2018, there were 2,467,956 shares available for future issuance pursuant to the DRIP.

NOTE 13: STOCK-BASED COMPENSATION EXPENSE

Pursuant to the Portland General Electric Company Stock Incentive Plan as amended and restated effective February 13, 2018 (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, or 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, 2016	458,792	$ 34.68
Granted	202,145	41.96
Forfeited	(64,840)	39.57
Vested	(196,721)	31.78
Outstanding as of December 31, 2017	399,376	37.98
Granted	198,864	37.99
Forfeited	(8,556)	39.73
Vested	(160,771)	36.77
Outstanding as of December 31, 2018	428,913	38.43

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 3,075,440 shares remain available for future issuance as of December 31, 2018.

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, 2018 and 2017.

Performance-based RSUs vest if performance goals are met at the end of a three-year performance period. Grants are based on three equally-weighted metrics: i) return on equity relative to allowed return on equity; ii) regulated asset base growth (applicable only for those grants made prior to 2017); and iii) a relative total shareholder return (TSR) of PGE's common stock as compared to an index of peer companies 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 (Committee). 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:

	2018		2017	
Risk-free interest rate		2.4%		1.5%
Expected dividend yield		—%		—%
Expected term (in years)		3.0		3.0
Volatility	14.7% -	21.8%	15.6% -	22.9%

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 89.9% and 97.8% of awarded performance-based RSUs for the respective 2018 and 2017 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $4 million for the year ended December 31, 2018 and $6 million for 2017.

Stock-based compensation, included in Administrative and General Expenses in the Statement of Income, was $5 million for the year ended December 31, 2018 and $7 million for 2017. Such amounts differ from those reported in the 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. Not included in Administrative and other expenses in the Statement of Income, is the net impact from these income tax payments, partially offset by the issuance of DERs, resulting in a charge to shareholders' equity of $2 million in 2018 and $3 million in 2017.

As of December 31, 2018, unrecognized stock-based compensation expense was $6 million, of which approximately $4 million and $2 million is expected to be expensed in 2019 and 2020, 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, 2018 or 2017.

NOTE 14: COMMITMENTS AND GUARANTEES

Purchase Commitments

As of December 31, 2018, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2019	**2020**	**2021**	**2022**	**2023**	**Thereafter**	**Total**
Capital and other purchase commitments	$ 143	$ 9	$ 1	$ 1	$ 1	$ 58	$ 213
Purchased Power:							
Electricity purchases	167	190	186	194	193	1,853	2,783
Capacity contracts	1	—	9	9	9	18	46
Public utility districts	12	11	9	8	8	35	83
Natural gas	54	42	31	31	30	208	396
Coal and transportation	6	—	—	—	—	—	6
Total	$ 383	$ 252	$ 236	$ 243	$ 241	$ 2,172	$ 3,527

Capital and other purchase commitments—Certain commitments have been made for 2019 and beyond that include those related to hydro licenses, upgrades to generation, 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 agreements with counterparties, which expire at varying dates through 2041, and power capacity contracts through 2028.

Public utility districts—PGE has long-term power purchase agreements with certain public utility districts (PUDs) in the state of Washington:

- Grant County PUD for the Priest Rapids and Wanapum projects, and
- Douglas County PUD for the Wells project.

Under the agreements, the Company is required to pay its proportionate share of the operating and debt service costs of the hydroelectric projects whether they are operable or not. In addition, although PGE's old agreement with Douglas County ended on August 31, 2018, a new contract became effective on September 1, 2018 that does not require contributions to Douglas County debt obligation or other costs, including the operation and maintenance costs of the projects. The new contract requires monthly payments for capacity that will not vary with annual project generation provided to PGE. The Company has estimated the capacity payments, which are subject to annual adjustments based on Douglas' loads, and included the estimated amounts in the table above. The future minimum payments for the PUDs in the preceding table reflect the principal and capacity payments only and do not include interest, operation, or maintenance expenses.

Selected information regarding these projects is summarized as follows (dollars in millions):

	Capacity Charges and Revenue Bonds as of December 31, 2018	PGE's Share as of December 31, 2018		Contract Expiration	PGE Capacity Charges and Debt Service Costs		
		Output	Capacity		2018	2017	2016
			(in MW)				
Priest Rapids and Wanapum	$ 1,236	8.6%	163	2052	$ 17	$ 16	$ 16
Wells	757	9.0	135	2028	11	11	10

The agreements for Priest Rapids, 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 responsible for a pro rata portion of the defaulting purchaser's share with no limitation, regardless of the reason for any default. 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 of the public utility district's outstanding debt for the portion of the project that benefits tax-exempt purchasers.

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. The Company also has a natural gas storage agreement for the purpose of fueling the Company's Port Westward Unit 1 (PW1), PW2, and Beaver natural gas-fired generating plants.

Coal and transportation—PGE has coal and related rail transportation agreements with take-or-pay provisions related to Boardman that expire at various dates through 2020.

Lease Obligations

As of December 31, 2018, PGE's estimated future minimum lease payments pursuant to capital, build-to-suit, and operating leases for the following five years and thereafter are as follows (in millions):

	Future Minimum Lease Payments		
	Capital Leases	Build-to-Suit	Operating Leases
2019	$ 6	$ 11	$ 4
2020	6	14	5
2021	6	13	5
2022	6	13	6
2023	5	13	7
Thereafter	67	225	97
Total minimum lease payments	96	$ 289	$ 124
Less imputed interest	47		
Present value of net minimum lease payments	49		
Less current portion	2		
Non-current portion	$ 47		

Capital Leases—PGE has entered into agreements to purchase natural gas transportation capacity via a 24-mile natural gas pipeline, Carty Lateral, that was constructed to serve the Carty facility. The Company has entered into a 30-year agreement to purchase the entire capacity of Carty Lateral, which is approximately 175,000 decatherms per day. At the end of the initial contract term, the Company has the option to renew the agreement in continuous three-year increments with at least 24-months prior written notice.

As of December 31, 2018, a capital lease asset of $57 million was reflected within Utility Plant and accumulated amortization of such assets of $8 million was reflected within Accumulated Provision for Depreciation, Amortization and Depletion in the Comparative Balance Sheet. The present value of the future minimum lease payments due under the agreement included $2 million within Obligations Under Capital Leases - Current and $47 million in Other noncurrent liabilities on the Comparative Balance Sheet. For ratemaking purposes capital leases are treated as operating leases; therefore, in accordance with the accounting rules for regulated operations, the amortization of the leased asset is based on the rental payments recovered from customers. Amortization of the leased asset of $3 million and interest charges of $4 million was recorded to Purchased Power in the Statement of Income through December 31, 2018 and 2017.

Build-to-suit—PGE entered into a 30-year lease agreement with a local natural gas company, NW Natural, to expand their current natural gas storage facilities, including the development of an underground storage reservoir and construction of a new compressor station and 13-miles of pipeline, which are collectively designed to provide no-notice storage and transportation services to PGE's PW1, PW2, and Beaver natural gas-fired generating plants. Pursuant to the agreement, in September 2016, PGE issued NW Natural a Notice To Proceed with construction of the expansion project, which the gas company estimates construction will be completed during the spring of 2019, at a cost of approximately $144 million. Due to the level of PGE's involvement during the construction period, the Company is deemed to be the owner of the assets for accounting purposes during the construction period. As a result, PGE has recorded $131 million and $108 million to CWIP and a corresponding liability for the same amount to Deferred Credits in the Comparative Balance Sheet as of December 31, 2018 and 2017, respectively. Pursuant to the adoption of the new lease accounting standard, Topic 842, PGE plans to derecognize the existing build-to-suit assets and liabilities as they are no longer considered to meet the build-to-suit criteria under the new standard. As a result, a ROU asset and lease liability will not be recognized on the Company's Comparative Balance Sheet until the lease commences, which is expected in the spring of 2019. For additional information regarding the new lease accounting standard, see Note 2, Summary of Significant Accounting Policies.

The table above reflects PGE's estimated future minimum lease payments pursuant to the agreement based on estimated costs.

Operating leases—PGE has various operating leases associated with leases of land, support facilities, and power purchase agreements that rely on identified plant that expire in various years, extending through 2096. Rent expense was $7 million in 2018 and $9 million in 2017. Contingent rents related to power purchase agreements was $14 million in 2018.

Sublease income was $4 million in 2018 and 2017.

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, 2018, 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

As of December 31, 2018, PGE had the following investments in jointly-owned plant (dollars in millions):

PGE	Plant	Accumulated	Construction

	Share	In-service Date	In-service	Depreciation*	Work In Progress
Boardman	90.00 %	1,980	$ 682	$ 617	$ —
Colstrip	20.00	1,986	549	363	10
Pelton/Round Butte	66.67	1,958 / 1,964	270	73	2
Total			$ 1,501	$ 1,053	$ 12

* Excludes AROs and accumulated asset retirement removal costs.

Under the respective joint operating agreements for the three generating facilities, each participating owner is responsible for financing its share of construction, operating, and leasing costs. PGE's proportionate share of direct operating and maintenance expenses of the facilities is included in the corresponding operating and maintenance expense categories in the Statement of Income.

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.

PGE 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) significant facts are in dispute; vi) a large number of parties are represented (including circumstances in which it is uncertain how liability, if any, would be shared among multiple defendants); or vii) a wide range of potential outcomes exist. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

Carty

In 2013, PGE entered into a turnkey engineering, procurement, and construction agreement (Construction Agreement) with Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership (collectively, the Contractor), affiliates of Abengoa S.A. - for the construction of the Carty natural gas-fired generating plant (Carty) located in Eastern Oregon. Liberty Mutual Insurance Company and Zurich American Insurance Company (together, the Sureties) provided a performance bond of $145.6 million (Performance Bond) in connection with the Construction Agreement. PGE, the Contractor, Abengoa S.A., and the Sureties are hereinafter collectively referred to as the Parties.

In December 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement. Following termination of the Construction Agreement, PGE brought on new contractors and construction resumed.

Carty was placed into service on July 29, 2016 and the Company began collecting its revenue requirement in customer prices on August 1, 2016, as authorized by the OPUC, based on the approved capital cost of $514 million. Actual costs for the construction of Carty exceeded the approved amount and, as of June 30, 2018, PGE had capitalized $640 million to Utility Plant.

The excess costs resulted from various matters relating to the resumption of construction activities following the termination of the Construction Agreement.

The Company sought recovery of excess construction costs and other damages pursuant to breach of contract claims against the Contractor and claims against the Sureties pursuant to the Performance Bond. The Sureties denied liability in whole under the Performance Bond, and the Contractor filed claims against the Company alleging wrongful termination of contract and related damages.

Various actions relating to this matter were filed in the U.S. District Court for the District of Oregon, in the Ninth Circuit Court of Appeals, and in the International Chamber of Commerce’s Court of Arbitration.

As a result of the foregoing events, PGE incurred a higher cost of service than what is reflected in the current authorized revenue requirement amount, primarily due to higher depreciation, interest, and legal expenses. These incremental expenses are recognized in the Company’s current results of operations. Such incremental expenses were $8 million and $14 million for the years ended December 31, 2018 and 2017, respectively.

On July 16, 2018, the Parties reached a settlement to resolve all claims relating to Carty construction between the Company and each of the Contractor, Abengoa S.A., and the Sureties. Under the terms of the settlement: i) the Sureties paid $130 million to PGE; and ii) the Contractor, Abengoa S.A., and the Sureties released all claims against the Company arising out of the Carty construction, and in return, PGE released all such claims against the Contractor, Abengoa S.A., and the Sureties.

The Company applied $120 million to reduce Utility Plant, net for undepreciated incremental construction costs, thus eliminating ongoing excess depreciation and amortization and interest expense with the remaining proceeds of $10 million from the cash settlement applied as a reduction of Administrative and other expenses.

In July 2016, PGE requested from the OPUC a regulatory deferral for the recovery of the revenue requirement associated with the excess capital costs for Carty. The Company requested that the OPUC delay its review of this deferral request until all legal actions with respect to this matter, including PGE’s actions against the Sureties, were resolved. As a result of the settlement described above, the Company withdrew the deferral application.

A de minimis amount of liens and claims filed for goods and services provided under third-party contracts with the Contractor remain in dispute. The Company believes the remaining claims by subcontractors are not owed by the Company and the Company is contesting the liens and claims in the courts.

EPA Investigation of Portland Harbor

An investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as Portland Harbor that began in 1997 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 as a federal Superfund site. PGE was included among the Potentially Responsible Parties (PRPs) as it has historically owned or operated property near the river.

In 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 remedial investigation had been completed pursuant to an agreement between the EPA and several PRPs known as the Lower Willamette Group (LWG), which did not include PGE. The LWG funded the remedial investigation and feasibility study and stated that it had incurred $115 million in investigation-related costs. The Company anticipates that such costs will ultimately be allocated to PRPs as a part of the allocation process for remediation costs of the EPA's preferred remedy.

The EPA finalized the feasibility study, along with the remedial investigation, and the results provided the framework for the EPA to determine a clean-up remedy for Portland Harbor that was documented in a Record of Decision (ROD) issued in January 2017. The ROD outlined the EPA's selected remediation plan for clean-up of the Portland Harbor site, which has an estimated total cost of $1.7 billion, comprised of $1.2 billion related to remediation construction costs and $0.5 billion related to long-term operation and maintenance costs, for a combined discounted present value of $1.1 billion. Remediation construction costs were estimated to be incurred over a 13-year period, with long-term operation and maintenance costs estimated to be incurred over a 30-year period from the start of construction. The EPA acknowledged the estimated costs are based on data that was outdated and that pre-remedial design sampling was necessary to gather updated baseline data to better refine the remedial design and estimated cost. In December 2017, the EPA announced that four PRPs had entered into an administrative order on consent to conduct this additional sampling, which was estimated to be completed in two years. PGE is not among the four PRPs performing this sampling.

PGE continues to participate in a voluntary process to determine an appropriate allocation of costs amongst the PRPs. Significant uncertainties remain surrounding facts and circumstances integral to the determination of such an allocation percentage, including results of the pre-remedial design sampling, a final allocation methodology and data with regard to property specific activities and history of ownership of sites within Portland Harbor. Based on the above facts and remaining uncertainties, PGE cannot reasonably estimate its potential liability or determine an allocation percentage that represents PGE's portion of the liability to clean-up Portland Harbor.

In cases in which 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 are referred to as Natural Resource Damages (NRD). The EPA does not manage NRD assessment activities but does provide claims information and coordination support to the NRD trustees. NRD assessment activities are typically conducted by a Council made up of the trustee entities for the site. 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.

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. The Company believes that PGE's portion of NRD liabilities related to Portland Harbor will not have a material impact on its results of operations, financial position, or cash flows.

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, and the method of allocation of costs amongst PRPs. It is probable that PGE will share in a portion of these costs. However, the Company does not currently have sufficient information to reasonably estimate the amount, or range, of its potential costs for investigation or remediation of Portland Harbor, although such costs could be material to PGE's financial position.

The impact of such costs to the Company's results of operations is mitigated by the Portland Harbor Environmental Remediation Account (PHERA) Mechanism. As approved in 2017, the PHERA allows the Company to defer and recover incurred environmental expenditures related to the Portland Harbor Superfund Site through a combination of third-party proceeds, such as insurance recoveries, and customer prices, as necessary. The mechanism established annual prudency reviews of environmental expenditures and third-party proceeds. Annual expenditures in excess of $6 million, excluding contingent liabilities, are subject to an annual earnings test. PGE's results of operations may be impacted to the extent such expenditures are deemed imprudent by the OPUC or ineligible per the prescribed earnings test. The Company continues to seek recovery of any costs resulting from the Portland Harbor proceeding through claims under insurance policies and regulatory recovery in customer prices.

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 2003, in two separate legal proceedings, lawsuits were filed against PGE on behalf of two classes of electric service customers: i) Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court; and ii) Morgan v. Portland General Electric Company, Marion County Circuit Court. 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 Oregon Supreme Court (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.

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

In 2015, based on a motion filed by PGE, the Marion County Circuit Court (Circuit Court) lifted the abatement on the class action proceedings and heard oral argument on the Company's motion for Summary Judgment. In March 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. In April 2016, the plaintiffs appealed the Circuit Court dismissal to the Court of Appeals for the State of Oregon. A Court of Appeals decision remains pending.

PGE believes that the 2014 OSC decision and the Circuit Court decisions that followed have reduced the risk of any loss to the Company beyond the amounts previously recorded and discussed above. However, because the class actions remain subject to a decision in the appeal, 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.

Deschutes River Alliance Clean Water Act Claims

On August 12, 2016, the Deschutes River Alliance (DRA) filed a lawsuit against the Company (Deschutes River Alliance v. Portland General Electric Company, U.S. District Court of the District of Oregon) that sought injunctive and declaratory relief against PGE under the Clean Water Act (CWA) related to alleged past and continuing violations of the CWA. Specifically, DRA claimed PGE had violated certain conditions contained in PGE's Water Quality Certification for the Pelton/Round Butte Hydroelectric Project (Project) related to dissolved oxygen, temperature, and measures of acidity or alkalinity of the water. DRA alleged the violations are related to PGE's operation of the Selective Water Withdrawal (SWW) facility at the Project.

The SWW, located above Round Butte Dam on the Deschutes River in central Oregon, is, among other things, designed to blend water from the surface of the reservoir with water near the bottom of the reservoir and was constructed and placed into service in 2010, as part of the FERC license requirements for the purpose of restoration and enhancement of native salmon and steelhead fisheries above the Project. DRA has alleged that PGE's operation of the SWW has caused the above-referenced violations of the CWA, which in turn have degraded the fish and wildlife habitat of the Deschutes River below the Project and harmed the economic and personal interests of DRA's members and supporters.

In September 2016, PGE filed a motion to dismiss, which asserted that the CWA does not allow citizen suits of this nature, and that the FERC has jurisdiction over all licensing issues, including the alleged CWA violations. On March 27, 2017, the court denied PGE's motion to dismiss. On April 7, 2017, the District Court granted an unopposed motion filed by the Confederated Tribes of Warm Springs (CTWS) to appear in the case as a friend of the court. The CTWS shares ownership of the Project with PGE but was not initially named as a defendant.

In March and April 2018, DRA and PGE filed cross-motions for summary judgment and PGE and the CTWS filed separate motions to dismiss. At a hearing on May 9, 2018, the Judge requested that PGE file an alternative motion to dismiss, which the Company and the CTWS filed on May 16, 2018. On June 11, 2018, the court denied the motions to dismiss filed in March 2018 and held that the CTWS was a necessary party to the lawsuit. DRA thereafter joined the CTWS as a defendant.

On August 3, 2018, the Judge denied DRA's motions for partial summary judgment and granted PGE's and CTWS's cross-motions for summary judgment, ruling in favor of PGE and CTWS. The Judge found that DRA had not shown a genuine dispute of material fact sufficient to support its contention that PGE and CTWS were operating the Project in violation of the CWA, and accordingly dismissed the case.

On August 24, 2018, DRA filed a motion seeking to alter or amend the judgment of dismissal, arguing that there is a genuine dispute of fact regarding PGE's compliance with requirements under the CWA. On October 1, 2018, the Judge denied DRA's motion to alter or amend the judgment of dismissal. On October 17, 2018, DRA filed an appeal to the Ninth Circuit Court of Appeals.

The Company cannot predict the outcome of this matter or determine the likelihood of whether the outcome of this matter will result in a material loss.

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(7,663,301)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(242,633)
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				(242,633)
5	Balance of Account 219 at End of Preceding Quarter/Year				(7,905,934)
6	Balance of Account 219 at Beginning of Current Year				(7,905,934)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,474,308
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				1,474,308
10	Balance of Account 219 at End of Current Quarter/Year				(6,431,626)

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)		(7,664,109)	[redacted]	
2			(242,633)		
3					
4			(242,633)	187,132,449	186,889,816
5	(808)		(7,906,742)	[redacted]	
6	(808)		(7,906,742)		
7			1,474,308		
8					
9			1,474,308	211,890,700	213,365,008
10	(808)		(6,432,434)	[redacted]	

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

Comprised of the net amount of the actuarial valuation of $(350,886) of non-qualified benefit plans net of taxes of $108,253.

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

Comprised of the net amount of the actuarial valuation of $2,033,521 of non-qualified benefit plans net of taxes of $(559,213).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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)	8,790,379,224	8,790,379,224
4	Property Under Capital Leases	56,820,000	56,820,000
5	Plant Purchased or Sold		
6	Completed Construction not Classified	1,661,898,877	1,661,898,877
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	10,509,098,101	10,509,098,101
9	Leased to Others		
10	Held for Future Use	4,615,275	4,615,275
11	Construction Work in Progress	346,348,706	346,348,706
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	10,860,062,082	10,860,062,082
14	Accum Prov for Depr, Amort, & Depl	4,948,724,140	4,948,724,140
15	Net Utility Plant (13 less 14)	5,911,337,942	5,911,337,942
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,638,743,404	4,638,743,404
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	309,980,736	309,980,736
22	Total In Service (18 thru 21)	4,948,724,140	4,948,724,140
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)	4,948,724,140	4,948,724,140

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
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					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 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
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			21
			22

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 2018/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	193,014,126	1,042,862
4	(303) Miscellaneous Intangible Plant	413,772,568	154,194,875
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	606,786,694	155,237,737
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,161,715	
9	(311) Structures and Improvements	257,998,507	780,470
10	(312) Boiler Plant Equipment	610,964,932	2,547,325
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	188,750,319	
13	(315) Accessory Electric Equipment	55,276,806	
14	(316) Misc. Power Plant Equipment	14,835,891	46,218
15	(317) Asset Retirement Costs for Steam Production	67,866,328	158,372
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,199,854,498	3,532,385
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	6,053,903	
28	(331) Structures and Improvements	74,258,776	916,435
29	(332) Reservoirs, Dams, and Waterways	349,104,157	27,694,982
30	(333) Water Wheels, Turbines, and Generators	68,732,269	769,818
31	(334) Accessory Electric Equipment	18,847,851	254,340
32	(335) Misc. Power PLant Equipment	2,475,748	76,050
33	(336) Roads, Railroads, and Bridges	13,240,012	124,029
34	(337) Asset Retirement Costs for Hydraulic Production	5,128	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	532,717,844	29,835,654
36	D. Other Production Plant		
37	(340) Land and Land Rights	48,946	
38	(341) Structures and Improvements	275,080,361	2,914,844
39	(342) Fuel Holders, Products, and Accessories	215,095,624	357,508
40	(343) Prime Movers		
41	(344) Generators	2,451,697,943	18,270,534
42	(345) Accessory Electric Equipment	119,663,643	1,240,368
43	(346) Misc. Power Plant Equipment	22,060,137	62,670
44	(347) Asset Retirement Costs for Other Production	16,698,437	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,100,345,091	22,845,924
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,832,917,433	56,213,963

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	13,300,374	
49	(352) Structures and Improvements	23,645,088	2,246,393
50	(353) Station Equipment	355,483,122	15,733,598
51	(354) Towers and Fixtures	48,749,648	64,725
52	(355) Poles and Fixtures	30,914,847	7,602,468
53	(356) Overhead Conductors and Devices	80,269,891	7,602,467
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)	552,683,411	33,249,651
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	22,402,147	1,337
61	(361) Structures and Improvements	43,994,899	4,381,600
62	(362) Station Equipment	529,526,466	88,398,009
63	(363) Storage Battery Equipment	384,933	
64	(364) Poles, Towers, and Fixtures	389,451,186	46,705,694
65	(365) Overhead Conductors and Devices	628,295,532	64,806,956
66	(366) Underground Conduit	15,881,536	8,602,380
67	(367) Underground Conductors and Devices	785,204,141	34,058,151
68	(368) Line Transformers	418,574,640	26,698,377
69	(369) Services	446,304,292	23,442,218
70	(370) Meters	161,887,834	9,803,790
71	(371) Installations on Customer Premises	376,133	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	91,344,446	6,374,342
74	(374) Asset Retirement Costs for Distribution Plant	476,732	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,534,104,917	313,272,854
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	9,744,439	3,472,545
87	(390) Structures and Improvements	127,348,362	13,795,842
88	(391) Office Furniture and Equipment	140,147,092	26,696,732
89	(392) Transportation Equipment	66,088,453	13,783,993
90	(393) Stores Equipment	3,730,446	305,699
91	(394) Tools, Shop and Garage Equipment	19,754,395	2,130,415
92	(395) Laboratory Equipment	9,698,221	256,593
93	(396) Power Operated Equipment	39,077,760	50,833
94	(397) Communication Equipment	133,934,104	20,493,447
95	(398) Miscellaneous Equipment	841,190	193,832
96	SUBTOTAL (Enter Total of lines 86 thru 95)	550,364,462	81,179,931
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)	550,429,751	81,179,931
100	TOTAL (Accounts 101 and 106)	10,076,922,206	639,154,136
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)	10,076,922,206	639,154,136

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 2018/Q4

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			194,056,988		3
47,091,753			520,875,690		4
47,091,753			714,932,678		5
					6
					7
			4,161,715		8
12,251			258,766,726		9
21,435			613,490,822		10
					11
			188,750,319		12
			55,276,806		13
			14,882,109		14
			68,024,700		15
33,686			1,203,353,197		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			6,053,903		27
398,457			74,776,754		28
216,470			376,582,669		29
			69,502,087		30
			19,102,191		31
			2,551,798		32
			13,364,041		33
			5,128		34
614,927			561,938,571		35
					36
			48,946		37
	-18,069,563		259,925,642		38
	-4,341,107		211,112,025		39
					40
181,603	-102,830,052		2,366,956,822		41
			120,904,011		42
	-1,261,230		20,861,577		43
			16,698,437		44
181,603	-126,501,952		2,996,507,460		45
830,216	-126,501,952		4,761,799,228		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 2018/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
			13,300,374		48
10,694			25,880,787		49
544,461			370,672,259		50
			48,814,373		51
			38,517,315		52
			87,872,358		53
					54
					55
			286,332		56
			34,109		57
555,155			585,377,907		58
					59
			22,403,484		60
4,664			48,371,835		61
2,230,023			615,694,452		62
			384,933		63
2,943,001			433,213,879		64
877,078			692,225,410		65
			24,483,916		66
			819,262,292		67
1,476,212			443,796,805		68
5,995			469,740,515		69
4,178,480			167,513,144		70
			376,133		71
					72
6,599			97,712,189		73
			476,732		74
11,722,052			3,835,655,719		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			13,216,984		86
316,849		-212,656	140,614,699		87
14,047,438		-12,579	152,783,807		88
1,823,830			78,048,616		89
260,185			3,775,960		90
496,338			21,388,472		91
469,522			9,485,292		92
2,517,819			36,610,774		93
119,897			154,307,654		94
			1,035,022		95
20,051,878		-225,235	611,267,280		96
					97
			65,289		98
20,051,878		-225,235	611,332,569		99
80,251,054	-126,501,952	-225,235	10,509,098,101		100
					101
					102
					103
80,251,054	-126,501,952	-225,235	10,509,098,101		104

Schedule Page: 204 Line No.: 45 Column: e

In 2013, PGE entered into a turnkey engineering, procurement, and construction agreement (Construction Agreement) with Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership (collectively, the Contractor), affiliates of Abengoa S.A. - for the construction of the Carty natural gas-fired generating plant (Carty) located in Eastern Oregon. Liberty Mutual Insurance Company and Zurich American Insurance Company (together, the Sureties) provided a performance bond of $145.6 million (Performance Bond) in connection with the Construction Agreement. PGE, the Contractor, Abengoa S.A., and the Sureties are hereinafter collectively referred to as the Parties.

In December 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement. Following termination of the Construction Agreement, PGE brought on new contractors and construction resumed.

Carty was placed into service on July 29, 2016 and the Company began collecting its revenue requirement in customer prices on August 1, 2016, as authorized by the OPUC, based on the approved capital cost of $514 million. Actual costs for the construction of Carty exceeded the approved amount and, as of June 30, 2018, PGE had capitalized $640 million to Electric utility plant. The excess costs resulted from various matters relating to the resumption of construction activities following the termination of the Construction Agreement.

The Company sought recovery of excess construction costs and other damages pursuant to breach of contract claims against the Contractor and claims against the Sureties pursuant to the Performance Bond. The Sureties denied liability in whole under the Performance Bond, and the Contractor filed claims against the Company alleging wrongful termination of contract and related damages.

On July 16, 2018, the Parties reached a settlement to resolve all claims relating to Carty construction between the Company and each of the Contractor, Abengoa S.A., and the Sureties. Under the terms of the settlement: i) the Sureties paid $130 million to PGE; and ii) the Contractor, Abengoa S.A., and the Sureties released all claims against the Company arising out of the Carty construction, and in return, PGE released all such claims against the Contractor, Abengoa S.A., and the Sureties.

The Company applied $126.5 million to reduce Electric utility plant within the adjustments column, with an offset to the accumulated depreciation reserve of $6.8 million. The remaining proceeds of $10.3 million from the cash settlement applied as a reduction of Administrative and other expenses.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

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	2,817,507
4	Sewell Easement, Washington County, OR	2009	Future	334,928
5	Rock Creek, Washington County, OR	2014	2019	590,122
6				
7	Other Land and Land Rights	Various	Various	329,127
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			4,615,275

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	Mist Natural Gas Storage	133,028,835
2	Marquam Substation Construction	27,245,150
3	Substation Communication Upgrade	16,730,443
4	Harborton Reliability Project	16,003,427
5	Transmission System Property Land Purchase	12,626,161
6	McGill Substation Capacity Additions	11,727,837
7	Horizon Substation Phase II Project	11,100,546
8	Colstrip Coal Capital Project	9,675,889
9	New Rock Creek Substation Construction	9,043,809
10	Repower Faraday Units 1-5	8,980,491
11	Round Butte Transmission Upgrades	7,254,173
12	Silverton Capacity Addition	6,225,231
13	Blue Lake Substation Upgrade	6,001,432
14	Beaver Generator Rewind Program	3,525,718
15	Identity Management and Access Control Software System Upgrade	3,201,847
16	Port Westward Turbine Upgrade	3,166,487
17	Garden Home Substation Upgrade	2,927,614
18	Enablon Software Upgrade	2,680,100
19	West Side Hydro Structural/Reliability Upgrade	2,647,544
20	Customer Underground Primary Service	2,488,701
21	Strategic Spare Substation Equipment Purchase	2,281,776
22	Purchase GIS Software Enterprise Licenses	2,150,000
23	Build Integrated Operations Center	2,124,474
24	King City - Substation Upgrades	2,082,268
25	River District Infrastructure - Install Vaults and Conduits	1,848,625
26	Development Operations Software Automation	1,841,420
27	Upgrade and Add Revenue Quality Meters	1,840,224
28	As-Built Drawings	1,768,951
29	Tapline Reliability Improvement Program (TRIP) Implementation	1,685,118
30	Hydro Control System Upgrade	1,368,835
31	Substation Fitness Project - Replace, Repair and Upgrade Aging Substation Equipment	1,362,770
32	Sherwood Security Upgrades	1,297,772
33	Transmission Pole Inspection and Replacement	1,271,621
34	T&D/Generation Key Metric Software Development	1,218,847
35	Bethel to Round Butte Fiber Optic Communication Project	1,106,884
36	Tektronix Substation Upgrade	1,090,454
37	Roseway Substation Expansion	1,075,989
38	Enterprise Performance Monitoring Software	1,025,917
39		
40		
41	Minor Projects, <$1 million, represents 6% of the Total CWIP Balance	21,625,326
42		
43	TOTAL	346,348,706

Schedule Page: 216 Line No.: 1 Column: a

Build-to-suit – PGE has entered into a 30-year lease agreement with a local natural gas company, NW Natural, to expand their current natural gas storage facilities, including the development of an underground storage reservoir and construction of a new compressor station and 13-mile pipeline, which will be designed to provide no-notice storage and transportation services to PGE's PW1, PW2, and Beaver natural gas-fired generating plants. Pursuant to the agreement, on September 30, 2016, PGE issued NW Natural a Notice To Proceed with construction of the expansion of the project, which the gas company estimates will be completed during the spring of 2019, at a cost of approximately $144 million. Due to the level of PGE's involvement during the construction period, the Company is deemed to be the owner of the assets for accounting purposes during the construction period. As a result, PGE has recorded $131 million to Account 107 Construction Work in Progress and a corresponding liability for the same amount to Account 253 Other deferred credits as of December 31, 2018. Pursuant to the adoption of the new lease accounting standard, Topic 842, PGE plans to derecognize the existing build-to-suit assets and liabilities as they are no longer considered to meet the build-to-suit criteria under the new standard. As a result, a right-of-use lease asset and lease liability will not be recognized on the Company's balance sheet until the lease commences, which is expected in the spring of 2019. Included in the Construction work in progress amount of $133 million is $2 million of other specific project costs incurred by PGE related to the Mist Natural Gas Storage Project.

Schedule Page: 216 Line No.: 8 Column: a

Jointly owned with Northwestern Energy, LLC, Talen Montana, LLC, Pudget Sound Energy, Inc, PacifiCorp, and Avista Corporation. Respondent's 20% share of jointly owned costs is reported.

Schedule Page: 216 Line No.: 11 Column: a

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	4,367,815,611	4,367,815,611		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	295,871,290	295,871,290		
4	(403.1) Depreciation Expense for Asset Retirement Costs	6,887,693	6,887,693		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	4,708,728	4,708,728		
7	Other Clearing Accounts	64,785	64,785		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	307,532,496	307,532,496		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	39,900,747	39,900,747		
13	Cost of Removal	534,603	534,603		
14	Salvage (Credit)	3,834,670	3,834,670		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	36,600,680	36,600,680		
16	Other Debit or Cr. Items (Describe, details in footnote):	-4,023	-4,023		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,638,743,404	4,638,743,404		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	979,305,164	979,305,164		
21	Nuclear Production				
22	Hydraulic Production-Conventional	238,866,024	238,866,024		
23	Hydraulic Production-Pumped Storage				
24	Other Production	799,450,261	799,450,261		
25	Transmission	242,395,690	242,395,690		
26	Distribution	2,125,536,504	2,125,536,504		
27	Regional Transmission and Market Operation				
28	General	253,189,761	253,189,761		
29	TOTAL (Enter Total of lines 20 thru 28)	4,638,743,404	4,638,743,404		

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

Depreciation associated with the movement of assets between non-utility and utility functional classes.

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			-43,189
9	Sub - TOTAL			-33,189
10				
11				
12				
13				
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15				
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36				
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38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 77,812,205		TOTAL	143,936

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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
-200,638	77,803,509	77,778,996		3
-200,638	77,803,509	77,779,996		4
				5
				6
		10,000		7
140,398	-75,000	22,209		8
140,398	-75,000	32,209		9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
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				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
-60,240	77,728,509	77,812,205		42

Schedule Page: 224 Line No.: 3 Column: f

Capital contributions associated with the purchase of the corporate headquarters building as a non-utility asset.

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 2018/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)	24,167,931	27,662,897	Generation
2	Fuel Stock Expenses Undistributed (Account 152)		40,377	
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	16,561,746	17,347,911	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	24,084,962	23,699,413	Generation
8	Transmission Plant (Estimated)	201,356	135,225	Transmission
9	Distribution Plant (Estimated)	5,248,553	5,661,207	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	2,266,799	2,388,836	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	48,363,416	49,232,592	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	490		
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	3,988,473	3,627,267	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	76,520,310	80,563,133	

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

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

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)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	56,279.00		10,033.00	
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	3,531.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	52,748.00		10,033.00	
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	1,201.44		193.15	
37	Add: Withheld by EPA				
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)		12		
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2020		2021		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
10,031.00		10,028.00		111,402.00		197,773.00		1
								2
								3
				1,320.00		1,320.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						3,531.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
10,031.00		10,028.00		112,722.00		195,562.00		29
								30
								31
								32
								33
								34
								35
193.15		193.15		3,815.55		5,596.44		36
								37
								38
				193.15		386.30		39
193.15		193.15		3,622.40		5,210.14		40
								41
								42
								43
					4		16	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 2018/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)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2020		2021		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
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22	Abandoned Trojan Nuclear Plant					
23	Decommissioning Costs;	347,889,429	26,687,360		2,330,680	26,054,936
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	347,889,429	26,687,360		2,330,680	26,054,936

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

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

(2) ($1,169,320) - Reclass of the noncurrent portion of the settlement proceeds from a legal matter associated with the costs of the Independent Spent Fuel Storage Installation from Account 254, Regulatory liability.

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	07-065 Feasability Study	9,385	561.6		456
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Other	877	561.7		
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231 Line No.: 22 Column: a

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	40,445,319		282	4,274,441	36,170,878
2	Previously Flowed to Customers	15,341,326		283	1,621,340	13,719,986
3	(Amort. period is based on the lives of the					
4	properties, approximately 25 years.)					
5						
6	Photovoltaic Volumetric Incentive Pilot	(38,475)	8,158,481	407.3	8,120,006	
7	(per OPUC Order No. 10-198 dtd 5/28/2010)					
8	Reauthorized OPUC Order No.15-185 dtd 6/09/2015)					
9						
10	Price Risk Management	203,456,437		547/555	72,018,361	131,438,076
11						
12	Deferred Broker Settlement		2,731,600			2,731,600
13						
14	Intervenor Funding (original deferral per OPUC	341,994	406,183	407.3	114,289	633,888
15	Order No. 03-388 dtd 7/2/2003)					
16						
17	Generation Plant Maintenance Deferral	684,492		557	684,492	
18	(per OPUC Order no. 08-601 dtd 12/29/2008;					
19	(amortization period: 1/1/2009 - 12/31/2018)					
20						
21	Port Westward Major Maintenance Accrual	1,167,775	4,840,479	553	5,120,517	887,737
22	(per OPUC GRC Order No.13-459, dtd 12/9/2013)					
23						
24	Residual Deferred Account	(172,996)	464,922			291,926
25	(per OPUC Order No. 10-279 dtd 7/23/2010)					
26						
27	Glass Insulator Deferral	4,870,761	832,855	571	92,056	5,611,560
28	(per OPUC Order No. 10-478 dtd 12/17/2010;					
29	UE 215 First Revenue Requirement Stipulation)					
30	Amortization period: 56 years					
31						
32	Pension Funding	218,490,327	24,832,392	219	16,892,530	226,430,189
33	Postretirement Funding	(269,336)		219	4,384,503	-4,653,839
34	(Per SFAS No. 158 adopted 12/31/2006;					
35	OPUC Order No. 07-051 dtd 2/12/2007)					
36						
37	Boardman Decommissioning Balancing	54,847	31,730			86,577
38	(Per Advice No. 11-07 dtd 05/27/2011)					
39						
40	Automated Demand Response Cost Recovery Mechanism	665,569	2,743,904	407.3	1,473,258	1,936,215
41	(Per OPUC Advice No. 17-29, dtd 11/13/17)					
42	(Amortization period 1/1/2018-12/31/2018)					
43						
44	TOTAL	535,236,011	76,948,960		144,958,372	467,226,599

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 2018/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	Demand Response Recovery Pilots					
2	Res Thermostat Direct Install		213,434			213,434
3	Res Pricing Program		95,602			95,602
4	(Per OPUC Order No. 18-381, dtd 10/11/2018)					
5						
6	IT O&M 2014 Deferral	1,736,800		Various	1,736,800	
7	(per OPUC GRC Order No.13-459, dtd 12/9/2013					
8	S-9 Partial Stipulation)					
9	Amortization period 1/1/2014-12/31/2018					
10						
11	CET 2014 Deferral	1,091,533		182.3	1,091,533	
12	(per OPUC GRC Order No.13-459, dtd 12/9/2013					
13	S-7 Partial Stipulation)					
14	Amortization period 1/1/2014-12/31/2018					
15						
16	CET 2015 Deferral	1,792,662		182.3	1,792,662	
17	(Per OPUC GRC Order NO. 13-459, UE-266,					
18	and Advice NO. 13-03)					
19	(amortization per OPUC Order No. 14-422,					
20	dtd 12/04/2014, 2015 GRC Docket UE-283					
21	amortization period 01/01/2015-12/31/2018)					
22						
23	CET 2016 Deferral	1,087,252		182.3	1,087,252	
24	(Per OPUC Order No. 13-459, UE-266,					
25	amortization per OPUC GRC UE-294,					
26	amortization period 01/01/2016-12/31/2018)					
27						
28	CET 2017 Deferral	6,791,703		182.3	6,791,703	
29	(Per OPUC Order No. 16-487, UM-1796,					
30	dtd 12/20/06)					
31						
32	CET 2018 Deferral		3,458,603	182.3	3,458,603	
33	(UM-1948, dtd 5/11/2018)					
34						
35	CET Deferral (2014-2018 vintages)		14,310,547	903	2,743,739	11,566,808
36	(amortization per OPUC Order No. 17-511,					
37	dtd 12/18/17)					
38	(Amortization period 01/01/2018-12/31/2022)					
39						
40	Schedule 110 Energy Efficiency	5,102	872,136	254/407.3	877,223	15
41	(per OPUC Advice No. 10-01)					
42						
43						
44	TOTAL	535,236,011	76,948,960		144,958,372	467,226,599

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	TID PPA Prepaid coal unearned revenue	695,200		253	695,200	
2	(per OPUC GRC Order NO. 14-442, UE-283,					
3	and Advice No. 14-03)					
4						
5	Deferred Cost - Pricing Program (Pricing Pilot)	1,942,141	496,783	407.3	1,437,715	1,001,209
6	(Per OPUC Order No. 15-203 dtd 6/23/15, UM 1708)					
7	(Amortization period 1/1/2018-12/31/2018)					
8						
9	Deferred Cost - DLC Thermostat Nest Pilot)	807,767	1,203,436	407.3	829,088	1,182,115
10	(Per OPUC Order No.15-203 dtd 6/23/15, UM 1708)					
11	(Amortization period 1/1/2018-12/31/2018)					
12						
13	Direct Access Reg Deferral 2016	(7,450)	7,450			
14	(Per OPUC Order 16-038, UM-1301)					
15	amortization period 01/01/2017-12/31/2017					
16						
17	Gresham Privilege Tax Collection Deferral	7,213,595	299,109	421	1,295,706	6,216,998
18	(Advice No. 17-05, Schedule 134, dtd 02/24/17)					
19	(Amortization period 1/1/2018-12/31/2022)					
20						
21	Portland Harbor Enviornmental	10,625,929	714,848	Various	3,387,304	7,953,473
22	Remediation Deferral					
23	(Per OPUC Order No. 17-071,					
24	Docket No. UM1789, dtd 03/02/17)					
25						
26	Residential Sch123 SNA Deferral-2016	566,324	6,791	456	654,638	-81,523
27	(Per OPUC Order No. 16-039, dtd 1/26/2016)					
28	(Amortization period 1/1/2018-12/31/2018)					
29						
30	Residential Sch123 SNA Deferral-2017	14,961,429	435,439	456	719,443	14,677,425
31	(reauthorized Advice No. 16-23, dtd 11/23/2016)					
32						
33	Residential Sch123 SNA Deferral-2018		2,839,114			2,839,114
34	(reauthorized Advice No. 16-23, dtd 11/23/2016)					
35						
36	Lost Revenue Recovery-2017		1,108,558			1,108,558
37	(Per OPUC Order No. 16-359 dtd 9/26/2016,					
38	amortization period 1/1/2019-12/31/2019,					
39	per Advice No. 17-24)					
40						
41	Residential Water Heater	60,643	1,004,172	407.3	736,629	328,186
42	(Per OPUC Order 17-09, UM-1827 dtd 04/19/17)					
43	(Amortization period 1/1/2018-12/31/2018)					
44	TOTAL	535,236,011	76,948,960		144,958,372	467,226,599

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	Trojan Decommissioning Deferral	827,341		254	827,341	
2	(amortization per OPUC Order No. 17-511,					
3	dtd 12/18/2017)					
4	(Amortization period 1/1/2018-12/31/2018)					
5						
6	Interest Rate Swap		4,166,551			4,166,551
7	Interest Rate Hedges for Long Term Debt					
8						
9	Transportation Electrification Prgm		220,275			220,275
10	(Per UM 1811, Order No. 18-124, dtd 4/12/2018)					
11						
12	Multifamily Water Heater		70,643			70,643
13	(Per Advice Filing No. 17-06, UM-1827,					
14	Order No. 17-224, dtd 6/27/2017)					
15						
16	Multnomah County Business Income Tax Balancing		382,923			382,923
17	(per Advice 11-27 dtd 10/27/2012)					
18						
19						
20						
21						
22						
23						
24						
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42						
43						
44	TOTAL	535,236,011	76,948,960		144,958,372	467,226,599

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

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

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

Amounts charged to accounts 253, 254, 421 and 431.

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	224,223	2,003,570	Various	1,854,073	373,720
3						
4	Net Co-owner / Trust Contributi	106,723	68,615,525	Various	68,457,598	264,650
5						
6	Deferred Rent - WTC Tenant	514,401		418	123,649	390,752
7	amort. through 2025					
8						
9	Deferred Revolving Credit	1,179,742		431	301,211	878,531
10	Agreement Fees					
11	amort. through 2020					
12						
13	Dispatchable Generation	11,342,898	2,073,412	903	2,195,857	11,220,453
14	various amort. periods from					
15	2009 and extending through 2028					
16						
17	LID Receivable from WTC Tenants	71,871		418	5,989	65,882
18	amort. over 20 yrs through 2029					
19						
20	Utility Property Sales-	24,521	53,861	254	19,397	58,985
21	Selling Expenses					
22						
23						
24						
25						
26						
27						
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29						
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43						
44						
45						
46						
47	Misc. Work in Progress	617,671				600,354
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	14,082,050				13,853,327

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Property Related	336,211,293	299,299,706
3	Regulatory Liabilities	13,525,752	26,413,341
4	Employee Benefits	128,251,123	134,186,632
5	Price Risk Management	57,591,286	41,765,483
6	Tax Credits & NOL's	49,582,793	51,996,251
7	Other	17,989,261	21,853,351
8	TOTAL Electric (Enter Total of lines 2 thru 7)	603,151,508	575,514,764
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	3,575,601	4,704,445
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	606,727,109	580,219,209

Notes

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

Line 7 - Other

	Ending Bal 12/31/2017	Ending Bal 12/31/2018
Bad Debt Expense	$1,744,633	$4,065,620
Deferred Revenue	3,605,073	2,538,575
Nuclear Decommissioning Trust	5,696,728	6,762,002
Renewable Energy Development	4,454,439	4,160,089
Miscellaneous	2,488,388	4,327,065
Total Line 7 - Other	$17,989,261	$21,853,351

Schedule Page: 234 Line No.: 17 Column: c

Line 17 - Other Non-Utility

	Ending Bal 12/31/2017	Ending Bal 12/31/2018
Property Related	$3,411,501	$4,567,734
Employee Benefits	164,100	136,711
Total Line 17 - Other Non-Utility	$3,575,601	$4,704,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201:			
2	Common Stock	160,000,000		
3				
4	Total_Com	160,000,000		
5				
6	Account 204:			
7	No Par Value Cumulative Preferred	30,000,000		
8				
9	Total_Pre	30,000,000		
10				
11				
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42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
89,267,959	1,215,804,775					2
						3
89,267,959	1,215,804,775					4
						5
						6
						7
						8
						9
						10
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						42

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 vaue 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	3,574,988
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 parent	8,317,516
21	SUBTOTAL ACCOUNT 211	12,428,737
22		
23		
24		
25		
26		
27		
28		
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32		
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36		
37		
38		
39		
40	TOTAL	18,838,837

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 (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	23,113,532
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	23,113,532

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	6.10% Series Due 4/15/2019 - Order No. 09-089 03/16/2009	300,000,000	2,386,224
14			222,000 D
15	5.43% Series Due 5/3/2040 - Order No. 09-245 06/22/2009	150,000,000	1,034,284
16	4.47% Series Due 6/15/2044 - Order No. 13-098 03/26/2013	150,000,000	1,113,047
17	4.47% Series Due 8/14/2043 - Order No. 13-098 03/26/2013	75,000,000	558,740
18	4.84% Series Due 12/15/2048 - Order No. 13-098 03/26/2013	50,000,000	311,154
19	4.74% Series Due 11/15/2042 - Order No. 13-098 03/26/2013	105,000,000	652,029
20	4.39% Series Due 8/15/2045 - Order No. 14-145 04/29/2014	100,000,000	645,383
21	4.44% Series Due 10/15/2046 - Order No. 14-145 04/29/2014	100,000,000	625,030
22	3.51% Series Due 11/15/2024 - Order No. 14-145 04/29/2014	80,000,000	501,502
23	3.55% Series Due 1/15/2030 - Order No. 14-399 11/12/2014	75,000,000	325,296
24	3.50% Series Due 5/15/2035 - Order No. 14-399 11/12/2014	70,000,000	305,128
25	2.51% Series Due 1/6/2021 - Order No. 14-399 11/12/2014	140,000,000	592,932
26	3.98% Series Due 11/21/2047 - Order No. 16-152 04/21/2016	150,000,000	-44,757
27	3.98% Series Due 8/3/2048 - Order No. 16-152 04/21/2016	75,000,000	-99,510
28	4.47% SERIES DUE 12-11-2048 Order No. 16-152 04/21/2016	75,000,000	
29			
30	Pollution Control Bonds (Guaranteed by Company) -		
31	Port of Morrow, OR Series 1998A 5% Due 5/1/2033	23,600,000	604,452
32	City of Forsyth, MT Series 1998A 5% Due 5/1/2033	97,800,000	2,615,167
33	TOTAL	2,511,483,849	19,520,650

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	SUBTOTAL ACCOUNT 221	2,511,400,000	19,520,650
2			
3	ACCOUNT 224 - OTHER LONG TERM DEBT		
4	City of Portland Improvement District Loan	83,849	
5	SUBTOTAL ACCOUNT 224	83,849	
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30			
31			
32			
33	TOTAL	2,511,483,849	19,520,650

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
04/16/2009	04/15/2019	04/16/2009	04/15/2019	300,000,000	18,300,000	13
						14
11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	8,145,000	15
6/27/2013	06/15/2044	6/27/2013	06/15/2044	150,000,000	6,705,000	16
8/29/2013	8/14/2043	8/29/2013	8/14/2043	75,000,000	3,352,500	17
12/16/2013	12/15/2048	12/16/2013	12/15/2048	50,000,000	2,420,000	18
11/15/2013	11/15/2042	11/15/2013	11/15/2042	105,000,000	4,977,000	19
8/15/2014	8/15/2045	8/15/2014	8/15/2045	100,000,000	4,390,000	20
10/15/2014	10/15/2046	10/15/2014	10/15/2046	100,000,000	4,440,000	21
11/17/2014	11/15/2024	11/17/2014	11/15/2024	80,000,000	2,808,000	22
1/15/2015	1/15/2030	1/15/2015	1/15/2030	75,000,000	2,662,500	23
5/15/2015	5/15/2035	5/15/2015	5/15/2035	70,000,000	2,450,000	24
1/6/2016	1/6/2021	1/6/2016	1/6/2021	140,000,000	3,514,000	25
11/21/2017	11/21/2047	11/21/2017	11/21/2047	150,000,000	5,970,000	26
8/3/2017	8/3/2048	8/3/2017	8/3/2048	75,000,000	2,985,000	27
12/11/2018	12/11/2048	12/11/2018	12/11/2048	75,000,000	167,625	28
						29
						30
05/28/1998	05/01/2033	05/28/1998	05/01/2033		983,333	31
05/28/1998	05/01/2033	05/28/1998	05/01/2033	97,800,000	4,890,000	32
				2,487,865,879	122,549,958	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.
				2,487,800,000	122,549,958	1
						2
						3
11/16/2009	11/16/2029			65,879		4
				65,879		5
						6
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						32
				2,487,865,879	122,549,958	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 2018/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)	211,890,700
2		
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion & Amortization	36,320,132
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Price Risk Management and Mark-to-Market	-67,851,810
11	Regulatory Credits	38,434,489
12	Other (See Footnote)	70,748,802
13		
14	Income Recorded on Books Not Included in Return	
15	Depreciation, Depletion & Amortization	-16,624,660
16	Regulatory Debits	62,221,939
17	Other (See Footnote)	2,466,930
18		
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	-52,713,650
21	State & Local Tax Deduction	-23,325,745
22	Other (See Footnote)	5,105,531
23		
24		
25		
26		
27	Federal Tax Net Income	266,672,658
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @ 21%	56,001,258
30	PTC C/F	-41,773,164
31	Parental Leave and STD	-91,383
32	RTA Adjustment	-2,065,796
33	Other Items Affecting Tax	-182,059
34	Total Federal Income Tax - PGE	11,888,856
35		
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44		

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

Line 12 - Deductions Recorded on Books Not Deducted for Return	
Qualified NDT	3,882,382
Meals & Entertainment	1,687,468
Political Activity	883,348
Bad Debts	8,439,952
Fines and Penalties	5,432
Employee Benefits	36,944,956
Federal Tax Expense	(2,960,332)
Orion Contingent Royalty Payments	(123,686)
Unamortized loss on reacquired debt	2,938,764
State Tax Expense	20,326,749
Deferred Revenue	(1,276,231)
Total Other	70,748,802

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

Line 17 - Income Recorded on Books Not Included in Return	
Key Man Insurance Proceeds	542,802
OCI	2,033,501
Miscellaneous	(109,373)
Total Other	2,466,930

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

Line 22 - Deductions on Return Not Charged Against Book Income	
Dividend Received Deduction	(45,000)
Prepaid	8,004,463
Renewable Energy Initiatives	(971,889)
Property Tax	(1,890,856)
Miscellaneous	8,813
Total Other	5,105,531

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 2018/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	201,979		738,017	719,251	
3	Income Tax		3,769,489	11,888,856	7,001,679	-44,603
4	Foreign Insurance Excise Tax					
5	FICA (Employer Share)	2,721,505		23,919,655	23,550,912	
6	Unemployment	59,986		148,484	144,370	
7	Power License	201,590	-218,210	2,259,053	2,372,319	
8	Superfund Tax					
9	SUBTOTAL Federal	3,185,060	3,551,279	38,954,065	33,788,531	-44,603
10	State of Montana:					
11	Income Tax		-42,742	495,390	425,000	
12	Electric Energy Producers	185,175		650,737	639,610	
13	Property Taxes	3,670,595		7,638,383	7,493,452	
14	SUBTOTAL Montana	3,855,770	-42,742	8,784,510	8,558,062	
15	State of Oregon:					
16	Corp Excise Tax		1,480,059	19,684,820	16,000,000	-10,254
17	Property Taxes		28,467,665	58,815,526	60,762,587	34,103
18	City Taxes & Licenses	3,443,660		44,609,289	44,609,489	
19	Public Utility Comm Fees			6,068,081	6,068,081	
20	Department of Energy		1,203,917	2,407,834	2,412,208	
21	Department of Enviro Quality	526,692		481,900	464,893	
22	Unemployment	224,166		1,623,745	1,887,326	
23	Water Power Fee		589,218	590,632	603,679	
24	Transportation Tax	433,554		1,878,585	1,881,967	
25	Workers Comp Assessment			160,389	215,745	
26	County & City Income Tax		214,495	1,261,499	1,290,000	-5,225
27	SUBTOTAL Oregon	4,628,072	31,955,354	137,582,300	136,195,975	18,624
28	State of Washington:					
29	Property Taxes	2,197,965		2,199,635	2,474,505	17,399
30	Sales Tax					
31	SUBTOTAL WASHINGTON	2,197,965		2,199,635	2,474,505	17,399
32	State of Utah					
33	Income Tax			1,516	1,516	
34	SUBTOTAL Utah			1,516	1,516	
35	State of California:					
36	Corporate Franchise Tax		482,714	586,562	125,273	273
37	SUBTOTAL California		482,714	586,562	125,273	273
38	Canada					
39	Goods & Services Tax					
40	SUBTOTAL Canada					
41	TOTAL	13,866,867	35,946,605	188,108,588	181,143,862	-8,307

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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 (l) 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
220,745					738,017	2
1,073,085		12,094,602			-205,746	3
		12,953			-12,953	4
3,090,248		13,321,791			10,597,864	5
64,100		82,396			66,088	6
272,328	-34,206				2,259,053	7
						8
4,720,506	-34,206	25,511,742			13,442,323	9
						10
113,132		497,083			-1,693	11
196,302		379,945			270,792	12
3,815,526		5,431,376			2,207,007	13
4,124,960		6,308,404			2,476,106	14
						15
2,194,507		19,747,944			-63,124	16
	30,380,623	56,116,788			2,698,738	17
3,470,914	23,454	44,609,289				18
					6,068,081	19
	1,208,291	2,408,186			-352	20
543,699					481,900	21
-39,415		755,016			868,729	22
	602,265				590,632	23
430,172		1,042,456			836,129	24
-55,356		89,002			71,387	25
-248,221		1,265,900			-4,401	26
6,296,300	32,214,633	126,034,581			11,547,719	27
						28
1,940,494		2,199,635				29
						30
1,940,494		2,199,635				31
						32
		1,516				33
		1,516				34
						35
-21,152		589,895			-3,333	36
-21,152		589,895			-3,333	37
						38
						39
						40
17,061,108	32,180,427	160,645,773			27,462,815	41

Schedule Page: 262 Line No.: 17 Column: f

Line 17 - Adjustments

$ 32,692	Clackamas County Refund
1,358	Bill-to-Others - Warm Springs
51	Washington County Refund
2	rounding adjustment
$ 34,103	Total Adjustments

Schedule Page: 262 Line No.: 29 Column: f

Line 29 - Adjustments

$17,399 Property Tax Billed to Partners

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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)						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
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			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Tenant security deposits	241,671				241,671
2						
3	Deferred Liability for Transferred	597,019	421	21,463		575,556
4	Non-Qualified Plan Benefits					
5						
6	Reserve for Portland Harbor	7,000,000	182.3	3,000,000		4,000,000
7	Remediation Costs					
8						
9	TID PPA prepaid coal stock	4,104,042	232	4,264,874	160,832	
10						
11	Deferral of Precedent Transmission	5,109,357	232/565	2,029,371	125,000	3,204,986
12	Service Agreement with DET, EDF					
13						
14	Northwest Natural Mist Storage	107,589,422			23,514,053	131,103,475
15	Capital Lease Accrual					
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	124,641,511		9,315,708	23,799,885	139,125,688

Schedule Page: 269 Line No.: 9 Column: c

Reclass current portion of accrual to account 232.

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

Reclass $1,026,196 current portion of accrual for Precedent Transmission Service Agreement of DET and EDF to account 232 and amortize $1,003,175 to offset incurred deferral fee expenses to account 565.

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 2018/Q4

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

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

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

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							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 2018/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	820,571,329	56,217,250	70,291,840
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	820,571,329	56,217,250	70,291,840
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	820,571,329	56,217,250	70,291,840
10	Classification of TOTAL			
11	Federal Income Tax	662,975,683	37,328,986	50,128,551
12	State Income Tax	147,582,816	17,701,896	18,901,874
13	Local Income Tax	10,012,830	1,186,368	1,261,415

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		182.3	14,173,327	254	9,898,886	802,222,298	2
							3
							4
			14,173,327		9,898,886	802,222,298	5
							6
							7
							8
			14,173,327		9,898,886	802,222,298	9
							10
			11,409,335		7,781,565	646,548,348	11
			2,595,387		1,992,826	145,780,277	12
			168,605		124,495	9,893,673	13

NOTES (Continued)

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	15,294,321		
4	Price Risk Management	1,640,770	6,268,956	2,289,711
5	Regulatory Assets	132,464,154	32,161,744	48,687,058
6	Regulatory Liabilities			
7	Other	12,424,484	65,185,628	65,451,655
8				
9	TOTAL Electric (Total of lines 3 thru 8)	161,823,729	103,616,328	116,428,424
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	560,618		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	162,384,347	103,616,328	116,428,424
20	Classification of TOTAL			
21	Federal Income Tax	113,749,368	91,951,953	100,923,282
22	State Income Tax	45,594,607	10,934,874	14,535,783
23	Local Income Tax	3,040,372	729,501	969,359

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		254	5,322,660	182.3	3,748,303	13,719,964	3
						5,620,015	4
						115,938,840	5
							6
						12,158,457	7
							8
			5,322,660		3,748,303	147,437,276	9
							10
							11
							12
							13
							14
							15
							16
							17
3,826,964	4,425,895	254	61,727	182.3	14,744	-85,296	18
3,826,964	4,425,895		5,384,387		3,763,047	147,351,980	19
							20
3,668,326	4,056,077		3,917,894		2,781,650	103,254,044	21
148,803	346,614		1,375,514		920,745	41,341,118	22
9,835	23,204		90,979		60,652	2,756,818	23

NOTES (Continued)

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

	Balance at Beg. Of Year	Balance at End Of Year
ASC 715 Pension & Post Retirement	60,010,768	60,988,492
ASC 980 Mark-to-Market	41,407,453	27,252,773
Miscellaneous	6,380,728	7,620,698
Price Risk Mgmt Deferral	14,543,063	10,038,496
Decoupling	4,283,366	4,711,148
CET Deferral	2,959,371	3,156,653
Feed in Tariff (FIT)	(42,725)	(17,372)
Portland Harbor (PHERA)	2,922,130	2,187,952
Total Regulatory Assets	132,464,154	115,938,840

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

	Balance at Beg. of Year	Balance at End of Year
Unamortized Loss on Reacquired Debt	5,207,755	4,399,594
Prepaid Property Tax	7,276,912	7,758,863
Other	(60,183)	0
Total Other	12,424,484	12,158,457

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

	Balance at Beg. Of Year	Balance at End Of Year
Trust-Owned Life Insurance Gain/Loss	359,152	155,692
Other	201,466	(240,988)
Total Other	560,618	(85,296)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Excess Deferred Income Taxes	332,316,824	190/411.1	15,015,368		317,301,456
2						
3	Gain on Asset Sales	2,348,512	407.4	2,210,725	616,736	754,523
4	(Per OPUC Order No. 01-777 dtd 8/31/2001)					
5						
6	Gain on Tradeable Renewable Energy Credits	(20,517)	407.4	149,507	170,024	
7	(Per OPUC Order No. 07-083 dtd 3/5/2007)					
8						
9	Boardman Severance	7,823,103			966,836	8,789,939
10	Advice No.14-18, dtd 11/3/2014					
11						
12	Asset Retirement Obligations:	52,208,413	407.3	3,059,655	4,133,416	53,282,174
13	Balancing Account					
14						
15	Carty Major Maintenance Deferral	1,122,653	456	5,266,926	4,988,552	844,279
16	(Per OPUC Order 15-356 UE-294					
17	dtd 11/3/15)					
18						
19	Colstrip Major Maintenance Deferral				2,580,408	2,580,408
20	(Per OPUC UE-319, Order No. 17-511,					
21	dtd 12/18/17)					
22						
23	Coyote Springs Major Maintenance Deferral	3,724,959	456	3,941,846	3,363,349	3,146,462
24	(Per OPUC Order No. 01-777 dtd 8/31/2001;					
25	reauthorization OPUC Order No. 10-478					
26	dtd 12/17/2010)					
27						
28	Port Westward 2 Major Maintenance Deferral	1,451,377	456	193,058	544,811	1,803,130
29	(Per OPUC 2015 GRC Docket UE-283,					
30	OPUC Order No.14-422, dtd 12/4/2014)					
31						
32	ISFSI Pollution Control Tax Credit Deferral	1,182,573	407.4	1,093,536	21,469	110,506
33	(Per OPUC Order No. 05-136, dtd 3/15/2005)					
34						
35	Zero Interest Program Loan Repayments	2,694,100			341,768	3,035,868
36	(Per Advice No. 05-19 dtd 12/20/2005)					
37						
38	Schedule 110 Energy Efficiency - Balancing Accout	515,321	182.3	166,543		348,778
39	(Per Advice No. 07-25 dtd 5/20/2008)					
40						
41	TOTAL	428,336,695		51,177,186	23,541,936	400,701,445

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 2018/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	Sunway 3 Investment Deferral	568,390	407.4	45,480		522,910
2	(Per UM 1480 dtd 4/01/2010;					
3	(Amortization over 20 years commencing 2010)					
4						
5	Trojan Decommissioning Deferral	2,195,347	407	3,860,883	2,064,534	398,998
6	(Per OPUC UE-319, Order No.17-511,					
7	dtd 12/18/2017)					
8	(Amortization period 1/1/2018-12/31/2018)					
9						
10	PRC Acquisition	3,489,392			52,901	3,542,293
11	(Per OPUC UE-283 Final GRC Order No.14-422,					
12	dtd 12/04/2014, Second Partial					
13	Stipulation dtd 9/2/2014)					
14						
15	Boardman Co-Fire Biomass Test Burn	72,827	456	72,827		
16	(Per OPUC Order No. 13-280 dtd 8/5/2013					
17	Updated Order No. 14-422 dtd 12/4/2014)					
18						
19	PPS Solar RRAAC Deferral	18	456	18		
20	(Per OPUC order No. 15-237 dtd 8/11/15					
21	order No. 15-304(UM1724) dtd 10/2/15)					
22						
23	North Fork Surface Collector	(9,729)	456	259,915	248,682	-20,962
24	(Per OPUC order 15-356 UE294 dtd 11/3/15)					
25						
26	Deferred Broker Settlement	2,972,483	182.3	2,556,683		415,800
27						
28	Direct Access Open Enrollment - 2017	634,950	447	619,465	35,275	50,760
29	(Per OPUC Order 17-109 UM-1301					
30	dtd 3/21/2017)					
31						
32	Photovoltaic Volumetric Incentive Pilot	1,537,245	182.3	510,855		1,026,390
33	(Per OPUC Order 10-198 dtd 5/28/2010					
34	reauthorized OPUC Order 15-185					
35	dtd 6/09/2015)					
36						
37	Portland Harbor Enviornmental Deferral	2,108,454	182.3	2,216,127	107,675	2
38	(Per OPUC Order No. 17-071, UM-1789					
39	dtd 03/02/17)					
40						
41	TOTAL	428,336,695		51,177,186	23,541,936	400,701,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	PHP PPA Expiration 2018 AUT Refund	9,400,000	555	9,937,769		-537,769
2	(Per OPUC Order 16-494, UE-308					
3	dtd 12/20/16)					
4						
5	Oregon Residential Clean Fuel Credit				3,305,500	3,305,500
6	(Per UM-1826, OPUC Order No. 17-512,					
7	dtd 12/18/2017)					
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
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35						
36						
37						
38						
39						
40						
41	TOTAL	428,336,695		51,177,186	23,541,936	400,701,445

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	890,376,597	900,171,801
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	648,540,186	650,481,084
5	Large (or Ind.) (See Instr. 4)	209,586,172	211,588,342
6	(444) Public Street and Highway Lighting	11,648,005	11,954,183
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,760,150,960	1,774,195,410
11	(447) Sales for Resale	177,074,310	122,591,295
12	TOTAL Sales of Electricity	1,937,225,270	1,896,786,705
13	(Less) (449.1) Provision for Rate Refunds	40,343,222	-10,337,496
14	TOTAL Revenues Net of Prov. for Refunds	1,896,882,048	1,907,124,201
15	Other Operating Revenues		
16	(450) Forfeited Discounts	6,004,495	3,415,326
17	(451) Miscellaneous Service Revenues	1,193,165	1,830,779
18	(453) Sales of Water and Water Power	-11,415	-26,668
19	(454) Rent from Electric Property	9,088,824	7,650,367
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	81,392,177	94,188,112
22	(456.1) Revenues from Transmission of Electricity of Others	10,560,749	8,511,435
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	108,227,995	115,569,351
27	TOTAL Electric Operating Revenues	2,005,110,043	2,022,693,552

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
7,415,759	7,879,585	772,389	762,211	2
				3
6,728,483	6,869,138	108,888	107,635	4
2,987,403	2,942,938	270	267	5
54,357	62,619	219	220	6
				7
				8
				9
17,186,002	17,754,280	881,766	870,333	10
4,690,990	3,574,665	37	36	11
21,876,992	21,328,945	881,803	870,369	12
				13
21,876,992	21,328,945	881,803	870,369	14

Line 12, column (b) includes $ -19,811,085 of unbilled revenues.

Line 12, column (d) includes -158,928 MWH relating to unbilled revenues

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

Includes $18,220,620 in revenue related to the delivery of 646,936 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 2017, 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 $16,760,202 in revenue related to the delivery of 623,048 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 2017, 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: b

Includes $24,428,602 in revenue related to the delivery of 1,388,558 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2018, 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 $19,828,473 in revenue related to the delivery of 1,340,132 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2017, 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.: 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:

E-Manager & Energy Experts
Field Service Charges
Meter Tamper Charges
Meter Test Charges
Meter Verification Charges
Reconnect Charges
Returned Check Charges
Returned Payment Charges

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:

E-Manager & Energy Experts
Field Service Charges

Meter Tamper Charges
Meter Test Charges
Meter Verification Charges
Reconnect Charges
Returned Check Charges
Returned Payment Charges

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

Other Electric Revenues consist of the following:

	2018
RPA Balancing	65,228,739
Sch 7 and Sch 32 Sales Norm Adj	8,936,787
Transmission Resale	5,584,768
Gas Resale	2,160,358
Boardman Fire Boiler with Biomass	2,009,470
Energy Trust Contract	868,657
Steam Sales	278,374
Automated Demand Response Deferred Costs	578,497
Hydro License Implementation and Compliance	30,467
Boardman Decommissioning Balancing Account	(351,754)
Port Westward 2 LTSA Exp Deferral	(966,836)
Boardman Severence	(2,580,408)
Carty Major Maintenance Deferral	(3,346,062)
Portland Harbor Environmental Remediation	1,852,562
Other	1,108,558
	$81,392,177

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

Other Electric Revenues consist of the following:

	2017
RPA Balancing	$65,143,350
Sch 7 and Sch 32 Sales Norm Adj	12,083,330
Transmission Resale	8,572,788
Gas Resale	5,552,442
Boardman Fire Boiler with Biomass	2,429,028
Energy Trust Contract	2,195,411
Steam Sales	1,892,218
Automated Demand Response Deferred Costs	999,373
Hydro License Implementation and Compliance	769,672
Boardman Decommissioning Balancing Account	(269,038)
Port Westward 2 LTSA Exp Deferral	(541,277)
Boardman Severence	(1,110,770)
Carty Major Maintenance Deferral	(1,122,653)
Portland Harbor Environmental Remediation	(3,560,400)
Other	1,154,638
	$94,188,112

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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					
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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 2018/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	6 Residential Pricing Pilot	41,669	4,947,870	1,831	22,758	0.1187
3	7 Residential Service	7,524,314	895,344,933	770,558	9,765	0.1190
4	15 Outdoor Area Lighting	2,309	795,895			0.3447
5	Residential Unbilled Revenue	-152,533	-10,712,101			0.0702
6	TOTAL Account 440	7,415,759	890,376,597	772,389	9,601	0.1201
7	General Comm. and Ind. Sales:					
8	15 Comm. Outdoor Lighting	13,527	2,757,944			0.2039
9	32 Small Nonresidential	1,650,852	180,786,550	91,007	18,140	0.1095
10	38 Optional Time of Day -	32,653	4,329,659	369	88,491	0.1326
11	Large Nonresidential					
12	47 Irrigation - Drainage - Small	22,773	4,268,187	2,797	8,142	0.1874
13	49 Irrigation - Drainage - Large	68,351	9,469,086	1,472	46,434	0.1385
14	83-S Large Nonresidential	2,891,233	262,635,937	11,473	252,003	0.0908
15	85-S Large Nonresidential	2,153,435	169,511,538	1,205	1,787,083	0.0787
16	89-S Large Nonresidential	51	27,808			0.5453
17	485-S COS Opt-Out - Lrg. Nonresid		14,977,122	216		
18	489-S COS Opt-Out - Lrg. Nonresid		388,311	1		
19	515-S DAS - Outdoor Area Lighting		6,351	2		
20	532-S DAS - Small Nonresidential		487,341	184		
21	583-S DAS - Large Nonresidential		2,462,919	117		
22	585-S DAS - Large Nonresidential		4,174,802	45		
23	Gen Comm. & Ind. Unbilled Revenue	-104,392	-7,743,369			0.0742
24	TOTAL Account 442 - Small	6,728,483	648,540,186	108,888	61,793	0.0964
25	Large Industrial Power Sales:					
26	75 Partial Requirements Service					
27	89-T Large Nonresidential	71,387	5,075,596	5	14,277,400	0.0711
28	85-P Large Nonresidential	586,979	47,278,347	183	3,207,536	0.0805
29	89-P Large Nonresidential	467,785	29,042,361	10	46,778,500	0.0621
30	90-P Large Nonresidential	1,762,565	102,711,119	5	352,513,000	0.0583
31	489-T COS Opt-Out - Lg. Nonreside		1,519,212	2		
32	485-P COS Opt-Out - Lrg. Nonresid		6,741,105	49		
33	489-P COS Opt-Out - Lg. Nonreside		17,959,050	12		
34	585-P DAS - Large Nonresidential		683,996	4		
35	589-P DAS - Large Nonresidential					
36	Large Industrial Unbilled Revenue	98,687	-1,424,614			-0.0144
37	TOTAL Account 442 - Large	2,987,403	209,586,172	270	11,064,456	0.0702
38	Street Lighting					
39	Various Public Street and					
40	Highway Lighting:					
41	TOTAL Billed	17,344,830	1,779,962,045	881,766	19,671	0.1026
42	Total Unbilled Rev.(See Instr. 6)	-158,928	-19,811,085	0	0	0.1247
43	TOTAL	17,185,902	1,760,150,960	881,766	19,490	0.1024

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	55,046	11,579,005	219	251,352	0.2104
2	Street Lighting Unbilled Rev	-689	69,000			-0.1001
3	TOTAL Account 444	54,357	11,648,005	219	248,205	0.2143
4	TOTAL Account 445					
5	Other Sales to Public Authorities					
6	Communication Devices Electr					
7	TOTAL Account 445					
8						
9						
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41	TOTAL Billed	17,344,830	1,779,962,045	881,766	19,671	0.1026
42	Total Unbilled Rev.(See Instr. 6)	-158,928	-19,811,085	0	0	0.1247
43	TOTAL	17,185,902	1,760,150,960	881,766	19,490	0.1024

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	Arizona Public Service	SF	WSPP-1	NA	NA	NA
2	Avangrid Renewables (was Iberdrola)	SF	EEI	NA	NA	NA
3	Avista Corp.	SF	WSPP-1	NA	NA	NA
4	BP Energy Company	SF	PGE-11	NA	NA	NA
5	Black Hills Power	SF	WSPP-1	NA	NA	NA
6	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
7	British Columbia Hydro & Power Auth		WSPP-1	NA	NA	NA
8	Brookfield Energy Marketing LP	SF	WSPP-1	NA	NA	NA
9	California Independent System Operator	SF	CAISO	NA	NA	NA
10	Calpine Energy Services, L.P.	SF	EEI	NA	NA	NA
11	Calpine Energy Services, L.P.	OS	WSPP-1	NA	NA	NA
12	Chelan County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
13	Citigroup Energy Inc.	SF	WSPP-1	NA	NA	NA
14	City of Burbank	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 2018/Q4

SALES FOR RESALE (Account 447)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	City of Glendale	SF	WSPP-1	NA	NA	NA
2	City of Redding	SF	WSPP-1	NA	NA	NA
3	Clatskanie Peoples Utility District	SF	WSPP-1	NA	NA	NA
4	Clean Power Alliance	OS	WSPP-1	NA	NA	NA
5	ConocoPhillips Company	SF	WSPP-1	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	Element Markets	OS	EEI	NA	NA	NA
9	ENMAX Energy Marketing Inc.	SF	WSPP-1	NA	NA	NA
10	Energy Keepers, Inc.	SF	WSPP-1	NA	NA	NA
11	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
12	Exelon Generation Company, LLC	SF	EEI	NA	NA	NA
13	Exelon Generation Company, LLC	OS	EEI	NA	NA	NA
14	Gridforce Energy Management	SF	EEI	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	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	Idaho Power Company	SF	WSPP-1	NA	NA	NA
2	Just Energy Solutions	OS	WSPP-1	NA	NA	NA
3	Load Balance Energy	OS	OATT	NA	NA	NA
4	Los Angeles Dept. Water Power	SF	WSPP-1	NA	NA	NA
5	Macquarie Energy LLC	SF	WSPP-1	NA	NA	NA
6	Marin Clean Energy	OS	WSPP-1	NA	NA	NA
7	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
8	Morgan Stanley Capital Group, Inc.	SF	PGE-11	NA	NA	NA
9	NaturEner Power Watch, LLC	SF	WSPP-1	NA	NA	NA
10	Nevada Power Company	SF	WSPP-1	NA	NA	NA
11	NextEra Energy Power Marketing, LLC	SF	WSPP-1	NA	NA	NA
12	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
13	PacifiCorp	SF	EEI	NA	NA	NA
14	PacifiCorp	LU	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 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	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	Powerex Corp.	SF	EEI	NA	NA	NA
2	Public Service Company of Colorado	SF	WSPP-1	NA	NA	NA
3	Public Utility District No. 1 of Clark	SF	WSPP-1	NA	NA	NA
4	Public Utility District No. 1 Okanogan	SF	WSPP-1	NA	NA	NA
5	Public Utility District No. 2 of Grant	SF	WSPP-1	NA	NA	NA
6	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
7	Rainbow Energy Marketing Company	SF	WSPP-1	NA	NA	NA
8	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
9	Sacramento Municipal Utility District	OS	WSPP-1	NA	NA	NA
10	San Francisco Water	OS	WSPP-1	NA	NA	NA
11	Seattle City Light	SF	WSPP-1	NA	NA	NA
12	Shell Energy North America (US), L.P.	SF	PGE-11	NA	NA	NA
13	Shell Energy North America (US), L.P.	OS	WSPP-1	NA	NA	NA
14	Snohomish County, PUD No.1, Washington	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Southern California Edison	SF	EEI	NA	NA	NA
2	Tacoma Power	SF	WSPP-1	NA	NA	NA
3	Tenaska Power Services Co.	SF	WSPP-1	NA	NA	NA
4	The Energy Authority, Inc.	SF	WSPP-1	NA	NA	NA
5	TransAlta Energy Marketing (U.S.), Inc.	SF	EEI	NA	NA	NA
6	TransCanada Energy Sales Ltd.	SF	WSPP-1	NA	NA	NA
7	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
8	Turlock Boardman Revenue	SF	WSPP-1	NA	NA	NA
9	Vitol Inc.	SF	WSPP-1	NA	NA	NA
10	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
11	Direct Access deferral 2018			NA	NA	NA
12	Direct Access amortization-2017			NA	NA	NA
13						
14	NON-RQ SALES:					
	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 2018/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						
2	Portland General Electric Company	SF	OA96137	923	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**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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.
		22,695		22,695	1
62,910		1,902,386		1,902,386	2
39,764		1,453,035		1,453,035	3
52,736		1,503,954		1,503,954	4
400		14,371		14,371	5
113,785		5,400,711		5,400,711	6
41		937		937	7
20		1,300		1,300	8
2,517,007		76,808,261		76,808,261	9
59,603		1,650,861		1,650,861	10
			11,580	11,580	11
10,009		175,624		175,624	12
31,617		1,733,260		1,733,260	13
2,842		281,910		281,910	14
0	0	0	0	0	
4,690,990	6,946,711	153,309,430	16,818,169	177,074,310	
4,690,990	**6,946,711**	**153,309,430**	**16,818,169**	**177,074,310**	

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
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6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
27		1,358		1,358	1
160		4,640		4,640	2
1,976		58,541		58,541	3
			700,000	700,000	4
114,050		2,798,600		2,798,600	5
3,845		265,950		265,950	6
7,166		187,914		187,914	7
			700,000	700,000	8
2,056		37,147		37,147	9
41,217		1,390,644		1,390,644	10
10,182		313,597		313,597	11
68,926		1,837,831		1,837,831	12
			5,683,138	5,683,138	13
561		24,381		24,381	14
0	0	0	0	0	
4,690,990	6,946,711	153,309,430	16,818,169	177,074,310	
4,690,990	**6,946,711**	**153,309,430**	**16,818,169**	**177,074,310**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
53,926		1,523,917		1,523,917	1
			150,000	150,000	2
25,653			-64,536	-64,536	3
205		11,800		11,800	4
138,818		2,395,875		2,395,875	5
			1,799,770	1,799,770	6
200		10,920		10,920	7
64,602		2,156,320		2,156,320	8
138		2,588		2,588	9
9		124		124	10
30		705		705	11
91,865		2,715,496		2,715,496	12
308,553		8,133,727		8,133,727	13
12,234			88,140	88,140	14
0	0	0	0	0	
4,690,990	6,946,711	153,309,430	16,818,169	177,074,310	
4,690,990	**6,946,711**	**153,309,430**	**16,818,169**	**177,074,310**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
197,185		4,852,188		4,852,188	1
1,600		38,000		38,000	2
		28,400		28,400	3
809		39,557		39,557	4
46		744		744	5
204,994		13,001,612		13,001,612	6
4,417		127,235		127,235	7
2,962		79,443		79,443	8
			2,223,925	2,223,925	9
			3,874,769	3,874,769	10
34,045		907,869		907,869	11
33,460		1,111,272		1,111,272	12
			1,082,816	1,082,816	13
17,780		487,577		487,577	14
0	0	0	0	0	
4,690,990	6,946,711	153,309,430	16,818,169	177,074,310	
4,690,990	**6,946,711**	**153,309,430**	**16,818,169**	**177,074,310**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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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.
124,783		5,656,424		5,656,424	1
5,592		136,495		136,495	2
27		486		486	3
28,510		970,852		970,852	4
51,775		1,781,883		1,781,883	5
120,672		2,452,928		2,452,928	6
21,401		2,152,752		2,152,752	7
		4,585,765		4,585,765	8
3,399		55,130		55,130	9
400		21,438		21,438	10
			619,465	619,465	11
			-50,898	-50,898	12
					13
					14
0	0	0	0	0	
4,690,990	6,946,711	153,309,430	16,818,169	177,074,310	
4,690,990	**6,946,711**	**153,309,430**	**16,818,169**	**177,074,310**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
	6,946,711			6,946,711	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
4,690,990	6,946,711	153,309,430	16,818,169	177,074,310	
4,690,990	**6,946,711**	**153,309,430**	**16,818,169**	**177,074,310**	

Schedule Page: 310 Line No.: 11 Column: j

Represents sales of renewable energy credits to Calpine.

Schedule Page: 310.1 Line No.: 4 Column: j

Represents sales of renewable energy credits to Clean Power Alliance.

Schedule Page: 310.1 Line No.: 8 Column: j

Represents sales of renewable energy credits to Element Market.

Schedule Page: 310.1 Line No.: 13 Column: j

Represents sales of renewable energy credits to Exelon Generation Company.

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

Represents sales of renewable energy credits to Just Energy Solutions.

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

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

Schedule Page: 310.2 Line No.: 6 Column: j

Represents sales of renewable energy credits to Marin Clean Energy.

Schedule Page: 310.2 Line No.: 14 Column: j

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

Schedule Page: 310.3 Line No.: 9 Column: j

Represents sales of renewable energy credits to Sacramento Municipal Utility District.

Schedule Page: 310.3 Line No.: 10 Column: j

Represents sales of renewable energy credits to San Francisco Water.

Schedule Page: 310.3 Line No.: 13 Column: j

Represents sales of renewable energy credits to Shell Energy North America.

Schedule Page: 310.4 Line No.: 8 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: 310.5 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	2,269,641	2,528,033
5	(501) Fuel	64,189,906	73,931,132
6	(502) Steam Expenses	6,842,388	6,803,509
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	9,158,903	9,085,127
11	(507) Rents	42,766	56,711
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	82,503,604	92,404,512
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	939,977	798,060
16	(511) Maintenance of Structures	993,457	1,015,128
17	(512) Maintenance of Boiler Plant	5,492,382	7,174,077
18	(513) Maintenance of Electric Plant	10,501,988	13,592,332
19	(514) Maintenance of Miscellaneous Steam Plant	1,360,371	1,296,207
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	19,288,175	23,875,804
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	101,791,779	116,280,316
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	861,193	755,713
45	(536) Water for Power	578,633	581,506
46	(537) Hydraulic Expenses	7,218,727	6,695,183
47	(538) Electric Expenses	1,349,687	1,071,589
48	(539) Miscellaneous Hydraulic Power Generation Expenses	3,596,649	3,173,488
49	(540) Rents	736,804	701,021
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	14,341,693	12,978,500
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	661,361	1,079,970
54	(542) Maintenance of Structures	15,391	-1,567
55	(543) Maintenance of Reservoirs, Dams, and Waterways	273,082	561,264
56	(544) Maintenance of Electric Plant	1,127,324	1,276,918
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,187,981	1,564,694
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	3,265,139	4,481,279
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	17,606,832	17,459,779

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	3,212,615	3,425,489
63	(547) Fuel	186,066,953	206,350,881
64	(548) Generation Expenses	9,631,775	10,137,232
65	(549) Miscellaneous Other Power Generation Expenses	14,382,382	12,059,952
66	(550) Rents	1,279,329	1,253,870
67	TOTAL Operation (Enter Total of lines 62 thru 66)	214,573,054	233,227,424
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	974,431	887,267
70	(552) Maintenance of Structures	548,659	357,361
71	(553) Maintenance of Generating and Electric Plant	42,640,875	47,172,190
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,502,039	1,120,428
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	45,666,004	49,537,246
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	260,239,058	282,764,670
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	257,926,636	244,313,723
77	(556) System Control and Load Dispatching	192,053	142,347
78	(557) Other Expenses	22,356,703	17,993,369
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	280,475,392	262,449,439
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	660,113,061	678,954,204
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,758,703	5,307,982
84			
85	(561.1) Load Dispatch-Reliability	14,421	13,940
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	987,062	629,769
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,177,969	1,205,851
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		25,400
90	(561.6) Transmission Service Studies	9,385	20,728
91	(561.7) Generation Interconnection Studies	877	
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	197,059	137,719
94	(563) Overhead Lines Expenses	67,003	101,597
95	(564) Underground Lines Expenses	1,199	
96	(565) Transmission of Electricity by Others	81,302,712	85,194,317
97	(566) Miscellaneous Transmission Expenses	7,052,153	6,313,534
98	(567) Rents	3,001,643	2,496,378
99	TOTAL Operation (Enter Total of lines 83 thru 98)	100,570,186	101,447,215
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	34,449	31,935
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	562,895	571,090
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,687,589	1,558,360
108	(571) Maintenance of Overhead Lines	482,177	671,082
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	22	2,087
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,767,132	2,834,554
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	103,337,318	104,281,769

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 2018/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	19,740,951	21,509,824
135	(581) Load Dispatching	1,929,614	1,677,843
136	(582) Station Expenses	882,668	1,033,545
137	(583) Overhead Line Expenses	1,915,263	2,481,905
138	(584) Underground Line Expenses	3,719,304	4,319,262
139	(585) Street Lighting and Signal System Expenses	502,923	574,742
140	(586) Meter Expenses	3,267,920	3,600,097
141	(587) Customer Installations Expenses	4,789,878	3,677,198
142	(588) Miscellaneous Expenses	8,302,615	8,826,946
143	(589) Rents	2,004,890	1,939,244
144	TOTAL Operation (Enter Total of lines 134 thru 143)	47,056,026	49,640,606
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	30,667	82,548
147	(591) Maintenance of Structures	138,383	142,377
148	(592) Maintenance of Station Equipment	5,505,867	4,904,078
149	(593) Maintenance of Overhead Lines	38,613,423	51,998,827
150	(594) Maintenance of Underground Lines	9,532,302	8,249,148
151	(595) Maintenance of Line Transformers	2,569,234	2,422,619
152	(596) Maintenance of Street Lighting and Signal Systems	644,785	793,545
153	(597) Maintenance of Meters	28,533	34,243
154	(598) Maintenance of Miscellaneous Distribution Plant	9,468,977	9,368,831
155	TOTAL Maintenance (Total of lines 146 thru 154)	66,532,171	77,996,216
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	113,588,197	127,636,822
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	377,022	533,423
161	(903) Customer Records and Collection Expenses	50,172,531	46,664,695
162	(904) Uncollectible Accounts	13,160,421	5,457,183
163	(905) Miscellaneous Customer Accounts Expenses	6,568,714	5,838,137
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	70,278,688	58,493,438

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	14,274,536	14,167,443
169	(909) Informational and Instructional Expenses	1,533,064	1,528,329
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	15,807,600	15,695,772
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	72,905,614	70,004,394
182	(921) Office Supplies and Expenses	23,646,995	21,720,812
183	(Less) (922) Administrative Expenses Transferred-Credit	10,755,645	10,623,570
184	(923) Outside Services Employed	-1,226,241	15,545,665
185	(924) Property Insurance	6,250,645	5,472,190
186	(925) Injuries and Damages	4,569,073	5,278,208
187	(926) Employee Pensions and Benefits	64,197,093	56,301,824
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	10,231,618	9,542,465
190	(929) (Less) Duplicate Charges-Cr.	2,456,901	2,309,778
191	(930.1) General Advertising Expenses	543,513	719,666
192	(930.2) Miscellaneous General Expenses	14,521,154	11,484,824
193	(931) Rents	5,097,132	5,090,394
194	TOTAL Operation (Enter Total of lines 181 thru 193)	187,524,050	188,227,094
195	Maintenance		
196	(935) Maintenance of General Plant	3,027,931	2,535,803
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	190,551,981	190,762,897
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,153,676,845	1,175,824,902

Schedule Page: 320 Line No.: 184 Column: b

Proceeds from the Carty settlement applied as a reduction of Administrative and other 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 2018/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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Arizona Public	SF	WSPP-1	NA	NA	NA
2	Avangrid Renewables (was Iberdrola)	SF	PGE-11	NA	NA	NA
3	Avangrid Renewables (was Iberdrola Ren	LU	PGE-11	NA	NA	NA
4	Avangrid Renewables (was Iberdrola)	LU	PGE-11	NA	NA	NA
5	Avista Corp. - AVWP (was WWP)	SF	WSPP-1	NA	NA	NA
6	Baldock Solar	LU	Baldock	NA	NA	NA
7	Bellevue Solar	LU	Bellevue	NA	NA	NA
8	Black Hills Power	SF	WSPP-1	NA	NA	NA
9	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
10	Brookfield Energy Marketing	SF	WSPP-1	NA	NA	NA
11	BP Energy Company	SF	PGE-11	NA	NA	NA
12	Burbank, City of	SF	WSPP-1	NA	NA	NA
13	California Independent System Operator	SF	CAISO	NA	NA	NA
14	Calpine Energy Services	SF	PGE-11	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Chelan County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
2	Citigroup Energy	SF	WSPP-1	NA	NA	NA
3	Clatskanie County PUD	SF	WSPP-1	NA	NA	NA
4	ConocoPhillips	SF	WSPP-1	NA	NA	NA
5	Covanta Marion	LU	QF83-118	NA	NA	NA
6	CP Energy Marketing (US)	SF	WSPP-1	NA	NA	NA
7	Douglas County, PUD No. 1, Washington	LU	Wells	NA	NA	NA
8	Douglas County, PUD No. 1, Washington	LF	Wells	NA	NA	NA
9	Douglas County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
10	EDF Trading North America, LLC	SF	WSPP-1	NA	NA	NA
11	Enmax	SF	PGE-11	NA	NA	NA
12	Energy Keepers, Inc. - ENKP	SF	WSPP-1	NA	NA	NA
13	ESI Vansycle Partners, LP	LU	WSPP-1	NA	NA	NA
14	Eugene Water & Electric Board	LU	WSPP-1	10	10	10
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Eugene Water & Electric Board	LU	ER94-717	NA	NA	NA
2	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
3	Evergreen Biomass	LU	201	NA	NA	NA
4	Exelon Generation Co.	SF	WSPP-1	NA	NA	NA
5	Gridforce Energy Management - GRID	SF	NWPP	NA	NA	NA
6	Grant County, PUD No. 2, Washington	LU	Wanapum	NA	NA	NA
7	Grant County, PUD No. 2, Washington	LU	Priest Rapids	NA	NA	NA
8	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
9	Grays Harbor, PUD No. 1	SF	WSPP-1	NA	NA	NA
10	Idaho Power Company	SF	WSPP-1	NA	NA	NA
11	JC Biomethane	LU	JCBIO	NA	NA	NA
12	Load Balance Energy	OS	OATT	NA	NA	NA
13	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
14	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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	NaturEner Power Watch, LLC	SF	WSPP-1	NA	NA	NA
2	Nevada Power Company	SF	WSPP-1	NA	NA	NA
3	NextEra Energy Power Marketing, LLC	SF	WSPP-1	NA	NA	NA
4	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
5	Norwest Energy 14	LU	201	NA	NA	NA
6	OE Solar 3, LLC	LU	201	NA	NA	NA
7	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
8	Outback Solar	LU	Outback	NA	NA	NA
9	Pacific Northwest Generating Company	SF	WSPP-1	NA	NA	NA
10	PacifiCorp	RQ	PP&L 147	NA	NA	NA
11	PacifiCorp	SF	PGE-11	NA	NA	NA
12	PaTu Wind	LU	WSPP-1	NA	NA	NA
13	Portland, City of	LU	#2821	NA	NA	NA
14	Portland, City of	OS	#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 2018/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	Powerex	SF	PGE-11	NA	NA	NA
2	Public Service Company of Colorado	SF	WSPP-1	NA	NA	NA
3	Public Utility District No. 1 of Clark	SF	WSPP-1	NA	NA	NA
4	Public Utility District No 1 of Benton	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	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
8	Seattle City Light	SF	WSPP-1	NA	NA	NA
9	Sheep Solar	LU	201	NA	NA	NA
10	Shell Energy	SF	WSPP-1	NA	NA	NA
11	Silverton Solar	LU	201	NA	NA	NA
12	Snohomish County, PUD No. 1, Washingt	SF	WSPP-1	NA	NA	NA
13	SP Solar 1, LLC	LU	201	NA	NA	NA
14	SP Solar 5, LLC	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 2018/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	SP Solar 6, LLC	LU	201	NA	NA	NA
2	SP Solar 7, LLC	LU	201	NA	NA	NA
3	SP Solar 8, LLC	LU	201	NA	NA	NA
4	Steel Bridge	LU	201	NA	NA	NA
5	Tacoma, City of	SF	WSPP-1	NA	NA	NA
6	Tenaska Power Services	SF	WSPP-1	NA	NA	NA
7	The Energy Authority	SF	WSPP-1	NA	NA	NA
8	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
9	TransCanada Energy Marketing	SF	WSPP-1	NA	NA	NA
10	Tri-State Generation	SF	WSPP-1	NA	NA	NA
11	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
12	Utah Municipal Power Systems	SF	WSPP-1	NA	NA	NA
13	Vitol Inc.	SF	WSPP-1	NA	NA	NA
14	Warm Springs Power Enterprises	LU	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 2018/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	WAPA - Upper Great Plains Region	SF	WSPP-1	NA	NA	NA
2	Westar Energy	LU	201	NA	NA	NA
3	Yamhill Solar	LU	Yamhill	NA	NA	NA
4	Lake Oswego Corporation	LU	201	NA	NA	NA
5	City of Salem	SF	WSPP-1	NA	NA	NA
6	Country Village Estates	OS	201	NA	NA	NA
7	Domaine Drouhin	OS	201	NA	NA	NA
8	Minikahada Hydropower Co	OS	201	NA	NA	NA
9	Starbuck Properties	OS	201	NA	NA	NA
10	Solar Payment Option	OS	215-217	NA	NA	NA
11	Tualatin Valley Water Dist	OS	201	NA	NA	NA
12	Oregon Energy Fund	OS	203	NA	NA	NA
13	Margin on Electric Financials			NA	NA	NA
14	Reserve Trading Credit Risk			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 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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	Green Power			NA	NA	NA
2	REC Retirement Expense			NA	NA	NA
3	Carbon Allowance Expense			NA	NA	NA
4						
5	Non-cash exchanges					
6	Energy Storage Expense					
7						
8	Non-cash exchanges					
9	Energy Storage Expense					
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)	
11,250				511,075		511,075	1
201,798				7,777,495		7,777,495	2
189,644				11,300,943		11,300,943	3
			2,445,000			2,445,000	4
109,222				4,882,216		4,882,216	5
1,742							6
1,502				188,033		188,033	7
2				64		64	8
1,169,864				25,503,015		25,503,015	9
2,225				89,919		89,919	10
183,732				1,026,911		1,026,911	11
80				800		800	12
826,863				25,654,093		25,654,093	13
1,011,585				26,140,694		26,140,694	14
9,002,682			2,529,000	254,998,358	399,278	257,926,636	

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)	
181,990				7,019,514		7,019,514	1
307,200				4,686,494		4,686,494	2
929				21,110		21,110	3
35,800				695,144		695,144	4
68,991				1,589,799		1,589,799	5
2,006				113,825		113,825	6
1,282,360				11,380,011		11,380,011	7
139,645				6,371,384		6,371,384	8
26,087				989,993		989,993	9
12,192				476,638		476,638	10
438				23,600		23,600	11
10,472				206,072		206,072	12
67,286				4,323,263		4,323,263	13
			84,000			84,000	14
9,002,682			2,529,000	254,998,358	399,278	257,926,636	

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)	
1,519							1
8,804				177,720		177,720	2
49,994				1,333,822		1,333,822	3
55,669				1,792,980		1,792,980	4
11				1,009		1,009	5
122,601				441		441	6
125,548				17,272,982		17,272,982	7
34				30		30	8
20							9
127,393				5,214,015		5,214,015	10
8,004				542,653		542,653	11
34,893				-189,464		-189,464	12
78,336				2,133,110		2,133,110	13
31,792				918,191		918,191	14
9,002,682			2,529,000	254,998,358	399,278	257,926,636	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
2				27		27	1
150				8,250		8,250	2
1,000				49,850		49,850	3
9,115				610,505		610,505	4
2,777				187,194		187,194	5
8,466				35,546		35,546	6
3,208				113,045		113,045	7
10,783				993,059		993,059	8
46,394				3,384,635		3,384,635	9
				-57,493		-57,493	10
222,278				6,354,581		6,354,581	11
29,022				2,236,964		2,236,964	12
72,096				1,965,753		1,965,753	13
				-9,400,000		-9,400,000	14
9,002,682			2,529,000	254,998,358	399,278	257,926,636	

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

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

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

MegaWatt Hours Purchased	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received	MegaWatt Hours Delivered	Demand Charges ($)	Energy Charges ($)	Other Charges ($)	Total (j+k+l) of Settlement ($)	
(g)	(h)	(i)	(j)	(k)	(l)	(m)	
136,435				8,537,650		8,537,650	1
200							2
90				500		500	3
20							4
100,126				2,841,404		2,841,404	5
1,034				109,364		109,364	6
1,985				188,780		188,780	7
62,412				1,757,469		1,757,469	8
2,845				156,160		156,160	9
123,890				4,028,277		4,028,277	10
2,780				162,038		162,038	11
105,125				1,594,645		1,594,645	12
2,836				160,741		160,741	13
2,902				158,607		158,607	14
9,002,682			2,529,000	254,998,358	399,278	257,926,636	

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)	
2,646				73,254		73,254	1
2,629				106,457		106,457	2
2,836				160,815		160,815	3
4,042				322,794		322,794	4
109,200				2,540,568		2,540,568	5
317				4,814		4,814	6
74,908				983,275		983,275	7
864,668				34,946,382		34,946,382	8
2,058				36,741		36,741	9
5				95		95	10
3,335				59,866		59,866	11
17,850				776,475		776,475	12
12,800				342,292		342,292	13
458,343				18,121,858		18,121,858	14
9,002,682			2,529,000	254,998,358	399,278	257,926,636	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1				33		33	1
228				5,360		5,360	2
995				124,481		124,481	3
18				1,360		1,360	4
				768		768	5
46				1,594		1,594	6
109				7,164		7,164	7
329				19,091		19,091	8
28				2,447		2,447	9
7,523							10
207				13,229		13,229	11
67					66,844	66,844	12
					-11,277,022	-11,277,022	13
					31,108	31,108	14
9,002,682			2,529,000	254,998,358	399,278	257,926,636	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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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)	
					12,406,018	12,406,018	1
					596,151	596,151	2
					-1,423,821	-1,423,821	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
9,002,682			2,529,000	254,998,358	399,278	257,926,636	

Schedule Page: 326.1 Line No.: 8 Column: b

The Douglas County contract expires on 9/30/28.

Schedule Page: 326.2 Line No.: 1 Column: g

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

Schedule Page: 326.2 Line No.: 12 Column: b

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: 326.6 Line No.: 6 Column: b

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

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

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

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

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

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

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

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

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

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

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

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

In accordance with Schedule 203, 215, 216(b) tariff any excess credits will be transferred to Low Income Assistance Program.

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

Margin on electric financial transactions.

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

Reserve for trading credit risk.

Schedule Page: 326.7 Line No.: 1 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: 326.7 Line No.: 2 Column: l

Expense of annual REC retirement to meet RPS compliance.

Schedule Page: 326.7 Line No.: 3 Column: l

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

Schedule Page: 326.7 Line No.: 9 Column: l

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

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 2018/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	3 Phases Renewables LLC	Bonneville Power Administration	Portland General Electric	OS
2	Avangrid Renewables, LLC	Bonneville Power Administration	Portland General Electric	OS
3	Avangrid Renewables, LLC	Balancing Authority of Northern C	Bonneville Power Administration	NF
4	Avangrid Renewables, LLC	Bonneville Power Administration	Balancing Authority of Northern C	NF
5	Avangrid Renewables, LLC	Bonneville Power Administration	Bonneville Power Administration	NF
6	Avista Corp	Bonneville Power Administration	Balancing Authority of Northern C	LFP
7	Avista Corp	Bonneville Power Administration	CAISO	LFP
8	Avista Corp	CAISO	Bonneville Power Administration	OS
9	Avista Corp	Bonneville Power Administration	CAISO	NF
10	Avista Corp	CAISO	Bonneville Power Administration	NF
11	Bonneville Power Administration	Bonneville Power Administration	Portland General Electric	FNO
12	Bonneville Power Administration	Bonneville Power Administration	Western Oregon Electric Coop	OLF
13	Bonneville Power Administration	Bonneville Power Administration	Other TVI Pumps	OLF
14	Bonneville Power Administration	Bonneville Power Administration	Canby People's Utility District	OLF
15	Bonneville Power Administration	Bonneville Power Administration	Columbia River PUD	OLF
16	Brookfield Energy Marketing	Bonneville Power Administration	Balancing Authority of Northern C	NF
17	Brookfield Energy Marketing	Bonneville Power Administration	CAISO	NF
18	Brookfield Energy Marketing	CAISO	Bonneville Power Administration	NF
19	Calpine Energy Services	Bonneville Power Administration	Portland General Electric	OS
20	Calpine Energy Services	Bonneville Power Administration	CAISO	NF
21	Canadian Wood Products	Bonneville Power Administration	CAISO	NF
22	Canadian Wood Products	CAISO	Bonneville Power Administration	NF
23	Constellation New Energy	Bonneville Power Administration	Portland General Electric	OS
24	Constellation New Energy	Bonneville Power Administration	Balancing Authority of Northern C	LFP
25	Constellation New Energy	Bonneville Power Administration	Portland General Electric	LFP
26	Constellation New Energy	Bonneville Power Administration	CAISO	LFP
27	Constellation New Energy	Bonneville Power Administration	CAISO	NF
28	EDF Trading North America LLC	Bonneville Power Administration	CAISO	NF
29	Macquarie Energy LLC	Bonneville Power Administration	CAISO	NF
30	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern C	LFP
31	Morgan Stanley Capital Group	Bonneville Power Administration	CAISO	LFP
32	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern C	NF
33	Morgan Stanley Capital Group	Bonneville Power Administration	CAISO	NF
34	Morgan Stanley Capital Group	CAISO	Bonneville Power Administration	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 2018/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	Pacificorp West	Portland General Electric	Portland General Electric	LFP
2	Pacificorp West	PacifiCorp	Various Substations	OLF
3	Powerex Inc.	Balancing Authority of Northern C	Bonneville Power Administration	LFP
4	Powerex Inc.	Bonneville Power Administration	Balancing Authority of Northern C	LFP
5	Powerex Inc.	Bonneville Power Administration	CAISO	LFP
6	Powerex Inc.	CAISO	Bonneville Power Administration	LFP
7	Powerex Inc.	Bonneville Power Administration	Balancing Authority of Northern C	OS
8	Powerex Inc.	Bonneville Power Administration	CAISO	OS
9	Powerex Inc.	Bonneville Power Administration	Balancing Authority of Northern C	NF
10	Powerex Inc.	Bonneville Power Administration	CAISO	NF
11	PUD No. 1 of Cowlitz Count	Bonneville Power Administration	Portland General Electric	LFP
12	PUD No. 1 of Franklin County	Bonneville Power Administration	Portland General Electric	LFP
13	PUD No. 1 of Klickitat County	Bonneville Power Administration	Portland General Electric	LFP
14	PUD No. 1 of Lewis County	Bonneville Power Administration	Portland General Electric	LFP
15	Puget Sound Energy Marketing	Bonneville Power Administration	Bonneville Power Administration	NF
16	Puget Sound Energy Marketing	CAISO	Bonneville Power Administration	NF
17	Seattle City Light	Bonneville Power Administration	Balancing Authority of Northern C	NF
18	Seattle City Light	Bonneville Power Administration	CAISO	NF
19	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern C	LFP
20	Shell Energy North America	Bonneville Power Administration	CAISO	LFP
21	Shell Energy North America	Bonneville Power Administration	Portland General Electric	OS
22	Shell Energy North America	Balancing Authority of Northern C	Bonneville Power Administration	NF
23	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern C	NF
24	Shell Energy North America	Bonneville Power Administration	CAISO	NF
25	Shell Energy North America	CAISO	Bonneville Power Administration	NF
26	Tacoma Power	Bonneville Power Administration	CAISO	LFP
27	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern C	LFP
28	The Energy Authority	Bonneville Power Administration	CAISO	LFP
29	The Energy Authority	Balancing Authority of Northern C	Bonneville Power Administration	OS
30	The Energy Authority	CAISO	Bonneville Power Administration	OS
31	The Energy Authority	Balancing Authority of Northern C	Bonneville Power Administration	NF
32	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern C	NF
33	The Energy Authority	Bonneville Power Administration	CAISO	NF
34	The Energy Authority	CAISO	Bonneville Power Administration	NF
	TOTAL			

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/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	Transalta Energy Marketing (US) Inc.	Balancing Authority of Northern C	Bonneville Power Administration	NF
2	Transalta Energy Marketing (US) Inc.	Bonneville Power Administration	Balancing Authority of Northern C	NF
3	Transalta Energy Marketing (US) Inc.	Bonneville Power Administration	CAISO	NF
4	Transalta Energy Marketing (US) Inc.	CAISO	Bonneville Power Administration	NF
5	Turlock Irrigation District	Bonneville Power Administration	Balancing Authority of Northern C	NF
6	Turlock Irrigation District	Bonneville Power Administration	CAISO	NF
7	Accrual			AD
8				
9				
10				
11				
12				
13				
14				
15				
16				
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19				
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25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
8	BPAT.PGE	PGE	11	18,119	-3,934	1
8	BPAT.PGE	PGE	251	101,126	-100,171	2
8	CaptainJack	JohnDay		25	25	3
8	JohnDay	CaptainJack		55	55	4
8	KFallsGen	JohnDay		331	331	5
7	JohnDay	CaptainJack		2,280	2,280	6
7	JohnDay	Malin500		677,977	677,977	7
8	Malin500	JohnDay		3,989	3,989	8
8	JohnDay	Malin500		3,011	3,011	9
8	Malin500	JohnDay		1,104	1,104	10
7	BPAT.PGE	PGE	160	58,375	-53,728	11
72	BPAT.PGE	Various Subs		12,604	11,926	12
72	BPAT.PGE	Various Subs		7,856	7,433	13
72	BPAT.PGE	Various Subs		178,733	169,113	14
72	BPAT.PGE	Various Subs		227,576	215,327	15
8	JohnDay	CaptainJack		41	41	16
8	JohnDay	Malin500		4,167	4,167	17
8	Malin500	JohnDay		960	960	18
8	BPAT.PGE	PGE	2,339	1,337,206	-1,338,836	19
8	JohnDay	Malin500		218	218	20
8	JohnDay	Malin500		235	235	21
8	Malin500	JohnDay		1,688	1,688	22
8	BPAT.PGE	PGE	896	2,874	-466,380	23
7	JohnDay	CaptainJack		151	151	24
7	JohnDay	COBH		70,408	70,408	25
7	JohnDay	Malin500		457,216	457,216	26
8	JohnDay	Malin500		3,970	3,970	27
8	JohnDay	Malin500		356	356	28
8	JohnDay	Malin500		1,650	1,650	29
7	JohnDay	CaptainJack		63,639	63,639	30
7	JohnDay	Malin500		1,673	1,673	31
8	JohnDay	CaptainJack		1,920	1,920	32
8	JohnDay	Malin500		2,633	2,633	33
8	Malin500	JohnDay		4,854	4,854	34
			4,014	**6,669,093**	**7,084,527**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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.
7	RoundButte	Redmond		32,756	32,756	1
Exchange	PACW.PGE	Various Subs		4,442	4,269,014	2
7	CaptainJack	JohnDay		10	10	3
7	JohnDay	CaptainJack		483,091	483,091	4
7	JohnDay	Malin500		930,384	930,384	5
7	Malin500	JohnDay		199,922	199,922	6
8	JohnDay	CaptainJack		75	75	7
8	JohnDay	Malin500		60	60	8
8	JohnDay	CaptainJack		636	636	9
8	JohnDay	Malin500		2,445	2,445	10
7	JohnDay	COB				11
7	JohnDay	COB				12
7	JohnDay	COB				13
7	JohnDay	COB				14
8	KFallsGen	JohnDay		47	47	15
8	Malin500	JohnDay		2,026	2,026	16
8	JohnDay	CaptainJack		1,725	1,725	17
8	JohnDay	Malin500		122	122	18
7	JohnDay	CaptainJack		174,188	174,188	19
7	JohnDay	Malin500		1,114,611	1,114,611	20
8	BPAT.PGE	PGE	357	175,105	-170,314	21
8	CaptainJack	JohnDay		561	561	22
8	JohnDay	CaptainJack		6,186	6,186	23
8	JohnDay	Malin500		32,388	32,388	24
8	Malin500	JohnDay		865	865	25
7	JohnDay	Malin500		49,174	49,174	26
7	JohnDay	CaptainJack		62,677	62,677	27
7	JohnDay	Malin500		93,385	93,385	28
8	CaptainJack	JohnDay		814	814	29
8	Malin500	JohnDay		5,045	5,045	30
8	CaptainJack	JohnDay		951	951	31
8	JohnDay	CaptainJack		2,870	2,870	32
8	JohnDay	Malin500		1,909	1,909	33
8	Malin500	JohnDay		4,287	4,287	34
			4,014	**6,669,093**	**7,084,527**	

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	CaptainJack	JohnDay		767	767	1
8	JohnDay	CaptainJack		82	82	2
8	JohnDay	Malin500		23,707	23,707	3
8	Malin500	JohnDay		6,563	6,563	4
8	JohnDay	CaptainJack		6,196	6,196	5
8	JohnDay	Malin500		1	1	6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
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						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			4,014	**6,669,093**	**7,084,527**	

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.
10,749			10,749	1
156,336			156,336	2
	22		22	3
	48		48	4
	291		291	5
	2,155		2,155	6
	640,834		640,834	7
				8
	6,850		6,850	9
	2,512		2,512	10
77,992			77,992	11
99,039			99,039	12
28,259			28,259	13
373,650			373,650	14
64,696			64,696	15
	44		44	16
	4,513		4,513	17
	1,040		1,040	18
1,558,934			1,558,934	19
	2,553		2,553	20
	593		593	21
	4,259		4,259	22
571,994			571,994	23
	18		18	24
	8,578		8,578	25
	55,702		55,702	26
	5,160		5,160	27
	392		392	28
	3,614		3,614	29
	62,652		62,652	30
	1,647		1,647	31
	3,497		3,497	32
	4,795		4,795	33
	8,840		8,840	34
3,166,568	**5,108,025**	**2,286,156**	**10,560,749**	

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.
	82,691		82,691	1
		247,349	247,349	2
	15		15	3
	735,448		735,448	4
	1,416,398		1,416,398	5
	304,357		304,357	6
				7
				8
	1,139		1,139	9
	4,380		4,380	10
	64,299		64,299	11
	64,299		64,299	12
	70,729		70,729	13
	70,729		70,729	14
	50		50	15
	2,139		2,139	16
	2,380		2,380	17
	168		168	18
	173,786		173,786	19
	1,112,038		1,112,038	20
224,919			224,919	21
	685		685	22
	7,548		7,548	23
	39,518		39,518	24
	1,055		1,055	25
	188,913		188,913	26
	-50,047		-50,047	27
	-74,567		-74,567	28
				29
				30
	1,454		1,454	31
	4,389		4,389	32
	2,920		2,920	33
	6,556		6,556	34
3,166,568	**5,108,025**	**2,286,156**	**10,560,749**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	1,067		1,067	1
	114		114	2
	32,968		32,968	3
	9,127		9,127	4
	10,669		10,669	5
	2		2	6
		2,038,807	2,038,807	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
3,166,568	**5,108,025**	**2,286,156**	**10,560,749**	

Schedule Page: 328 Line No.: 1 Column: d
Represents non-billed redirected MWHs of 3 Phases Renewables, LLC’s service.
Schedule Page: 328 Line No.: 2 Column: d
Represents non-billed redirected MWHs of Avangrid Renewables, LLC’s service.
Schedule Page: 328 Line No.: 6 Column: d
Contract with Avista Corporation Washington Water Power Division continues until terminated.
Schedule Page: 328 Line No.: 7 Column: d
Contract with Avista Corporation Washington Water Power Division continues until terminated.
Schedule Page: 328 Line No.: 8 Column: d
Represents non-billed redirected MWHs of Avista Corporation Washington Water Power Division’s service.
Schedule Page: 328 Line No.: 12 Column: d
Contract with Bonneville Power Administration continues until terminated.
Schedule Page: 328 Line No.: 13 Column: d
Contract with Bonneville Power Administration continues until terminated.
Schedule Page: 328 Line No.: 14 Column: d
Contract with Bonneville Power Administration continues until terminated.
Schedule Page: 328 Line No.: 15 Column: d
Contract with Bonneville Power Administration continues until terminated.
Schedule Page: 328 Line No.: 19 Column: d
Represents non-billed redirected MWHs of Calpine Energy Services’ service.
Schedule Page: 328 Line No.: 23 Column: d
Represents non-billed redirected MWHs of Constellation New Energy's service.
Schedule Page: 328 Line No.: 24 Column: d
Contract with Constellation New Energy expires 01/01/2034.
Schedule Page: 328 Line No.: 25 Column: d
Contract with Constellation New Energy expires 01/01/2034.
Schedule Page: 328 Line No.: 26 Column: d
Contract with Constellation New Energy expires 01/01/2034.
Schedule Page: 328 Line No.: 30 Column: d
Contract with Morgan Stanley Capital Group Inc expires 01/01/2034.
Schedule Page: 328 Line No.: 31 Column: d
Contract with Morgan Stanley Capital Group Inc expires 01/01/2034.
Schedule Page: 328.1 Line No.: 1 Column: d
Contract with PacifiCorp continues until terminated.
Schedule Page: 328.1 Line No.: 2 Column: d
Exchange agreement with PacifiCorp.
Schedule Page: 328.1 Line No.: 3 Column: d
Contract with Powerex Corp continues until terminated.
Schedule Page: 328.1 Line No.: 4 Column: d
Contract with Powerex Corp continues until terminated.
Schedule Page: 328.1 Line No.: 5 Column: d
Contract with Powerex Corp continues until terminated.
Schedule Page: 328.1 Line No.: 6 Column: d
Contract with Powerex Corp continues until terminated.
Schedule Page: 328.1 Line No.: 7 Column: d
Represents non-billed redirected MWHs of Powerex Inc.'s service.
Schedule Page: 328.1 Line No.: 8 Column: d
Represents non-billed redirected MWHs of Powerex Inc.'s service.
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: d

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

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: d

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

Schedule Page: 328.1 Line No.: 19 Column: d

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

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

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

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

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

Schedule Page: 328.1 Line No.: 26 Column: d

Contract with Tacoma Power continues until terminated.

Schedule Page: 328.1 Line No.: 27 Column: d

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

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

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

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

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

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

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

Schedule Page: 328.2 Line No.: 7 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 (including financial settlement of electrical losses associated with the use of the transmission system)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 2018/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					
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27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp	NF	12,711	12,711		73,019		73,019
2	Bonneville Power Admin	LFP			62,865,272			62,865,272
3	Bonneville Power Admin	OS					14,830,831	14,830,831
4	Bonneville Power Admin	SFP	48,070	48,070		168,232		168,232
5	Bonneville Power Admin	NF	28,563	28,563		177,261		177,261
6	Bonneville Power Admin	AD					-144,978	-144,978
7	Calpine Energy Services	LFP	9,506	9,506		28,518		28,518
8	Columbia River PUD	SFP	12	12		20,351		20,351
9	Eugene Water & Electric	LFP	24	24		43,435		43,435
10	Idaho Power Company	NF	184,706	184,706		581,073		581,073
11	McMinnville Water & Lig	LFP	895	895		8,621		8,621
12	Montana, State of	OS					2,424,312	2,424,312
13	NorthWestern Energy	NF	30,487	30,487		138,217		138,217
14	PacifiCorp	OS					86,883	86,883
15	Seattle City Light	NF	1,478	1,478		1,665		1,665
16								
	TOTAL		316,452	316,452	62,865,272	1,240,392	17,197,048	81,302,712

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

Represents the Bonneville Power Administration PTP contracts that have termination dates that range from 10/31/2019 thru 9/30/2027.

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

Represents Bonneville Power Administration Ancillary Transmission Services.

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

Represents Bonneville Power Administration prior period adjustments and monthly billing offsets.

Schedule Page: 332 Line No.: 9 Column: b

Represents Eugene Water & Electric Board contract which terminates on 12/1/2020.

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

Represents McMinnville Water & Light contract which terminates on 12/31/2030.

Schedule Page: 332 Line No.: 12 Column: g

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

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

Represents PacifiCorp's Linneman Transmission Services.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	3,331,148
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	1,983,081
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,822,753
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Involuntary Severance	3,603,322
7	Directors Pension	210,056
8	Directors Fees & Expenses	210,169
9	Directors & Officers Expenses	2,244,595
10	Misc. Admin Expenses	313,006
11	Colstrip - PPL Montana	542,845
12	Internal & External Reporting	
13	Amounts Previous Charged to Other Accounts	260,179
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46	TOTAL	14,521,154

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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			58,972,528		58,972,528
2	Steam Production Plant	33,478,519	6,315,164			39,793,683
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	21,097,595	69			21,097,664
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	84,506,557	566,832			85,073,389
7	Transmission Plant	12,221,571	1			12,221,572
8	Distribution Plant	106,690,668	5,528			106,696,196
9	Regional Transmission and Market Operation					
10	General Plant	37,876,380	99			37,876,479
11	Common Plant-Electric					
12	TOTAL	295,871,290	6,887,693	58,972,528		361,731,511

B. Basis for Amortization Charges

Five year and ten year amortization of computer software.

Five, twenty-five, and thirty year amortization of permits.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	311 - Boardman Coal Pla	107,773	40.00	-10.00	50.00	Life Span - 2020	2.00
13	311 - Boardman PGE-BAL	33,785	40.00	-10.00	50.00	Life Span - 2020	2.00
14	311 - Colstrip Prod - P	117,209	46.00	-4.00	8.33	Life Span - 2030	12.00
15	311 - Colstrip Trans NW		46.00	-4.00	8.33	Life Span - 2030	12.00
16	312 - Boardman Coal Pla	270,012	40.00	-10.00	50.00	Life Span - 2020	2.00
17	312 - Boardman PGE-BAL	87,847	40.00	-10.00	50.00	Life Span - 2020	2.00
18	312 - Colstrip Prod - P	255,632	46.00	-4.00	8.33	Life Span - 2030	12.00
19	312 - Colstrip Trans NW		46.00	-4.00	8.33	Life Span - 2030	12.00
20	314 - Boardman Coal Pla	87,021	40.00	-10.00	50.00	Life Span - 2020	2.00
21	314 - Boardman PGE-BAL	28,860	40.00	-10.00	50.00	Life Span - 2020	2.00
22	314 - Colstrip Prod - P	72,869	46.00	-4.00	8.33	Life Span - 2030	12.00
23	314 - Colstrip Trans NW		46.00	-4.00	8.33	Life Span - 2030	12.00
24	315 - Boardman Coal Pla	24,001	40.00	-10.00	50.00	Life Span - 2020	2.00
25	315 - Boardman PGE-BAL	7,773	40.00	-10.00	50.00	Life Span - 2020	2.00
26	315 - Colstrip Prod - P	23,504	46.00	-4.00	8.33	Life Span - 2030	12.00
27	315 - Colstrip Trans NW		46.00	-4.00	8.33	Life Span - 2030	12.00
28	316 - Boardman Coal Pla	6,389	40.00	-10.00	50.00	Life Span - 2020	2.00
29	316 - Boardman PGE-BAL	2,131	40.00	-10.00	50.00	Life Span - 2020	2.00
30	316 - Colstrip Prod - P	6,362	46.00	-4.00	8.33	Life Span - 2030	12.00
31	316 - Colstrip Trans NW		46.00	-4.00	8.33	Life Span - 2030	12.00
32	317 - ARC STEAM	68,025				SQ	
33	331 - Faraday - FERC #2	6,986	110.00	-58.00	2.72	R2.5	36.76
34	331 - North Fork FERC #	9,071	110.00	-78.00	2.71	R2.5	36.90
35	331 - Oak Grove -FERC #	8,627	110.00	-57.00	2.76	R2.5	36.23
36	331 - Oak Grove Timothy	6,205	110.00	-57.00	2.76	R2.5	36.23
37	331 - OAK	463	110.00	-57.00	2.76	R2.5	36.23
38	331 - Pelton Proj - FER	6,200	110.00	-176.00	2.75	R2.5	36.36
39	331 - River Mill FERC #	6,827	110.00	-101.00	2.86	R2.5	34.97
40	331 - Round Butte Plant	12,089	110.00	-78.00	2.73	R2.5	36.23
41	331 - Sullivan FERC # 2	18,309	110.00	-31.00	5.25	R2.5	19.05
42	332 - Faraday - FERC #2	32,813	105.00	-58.00	2.72	R3	36.76
43	332 - North Fork FERC #	86,490	105.00	-78.00	2.65	R3	37.74
44	332 - Oak Grove -FERC #	21,468	105.00	-57.00	2.71	R3	36.90
45	332 - Oak Grove Timothy	5,238	105.00	-57.00	2.71	R3	36.90
46	332 - Pelton Proj - FER	18,983	105.00	-176.00	2.87	R3	34.84
47	332 - River Mill FERC #	58,989	105.00	-101.00	2.65	R3	37.74
48	332 - Round Butte Plant	120,038	105.00	-78.00	2.65	R3	37.74
49	332 - Sullivan FERC # 2	32,565	105.00	-31.00	5.21	R3	19.19
50	333 - Faraday - FERC #2	6,752	90.00	-58.00	2.89	S1	34.60

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	333 - North Fork FERC #	11,832	90.00	-78.00	3.02	S1	33.11
13	333 - Oak Grove -FERC #	9,000	90.00	-57.00	2.90	S1	34.48
14	333 - Pelton Proj - FER	4,295	90.00	-176.00	3.24	S1	30.86
15	333 - River Mill FERC #	5,927	90.00	-101.00	2.88	S1	34.72
16	333 - Round Butte Plant	21,399	90.00	-78.00	2.76	S1	36.23
17	333 - Sullivan FERC # 2	10,295	90.00	-31.00	5.32	S1	18.80
18	334 - Faraday - FERC #2	2,578	60.00	-58.00	3.33	R2.5	30.03
19	334 - North Fork FERC #	1,097	60.00	-78.00	3.31	R2.5	30.21
20	334 - Oak Grove -FERC #	3,872	60.00	-57.00	3.48	R2.5	28.74
21	334 - Pelton Proj - FER	2,449	60.00	-176.00	3.25	R2.5	30.77
22	334 - River Mill FERC #	2,602	60.00	-101.00	3.29	R2.5	30.40
23	334 - Round Butte Plant	2,318	60.00	-78.00	3.19	R2.5	31.35
24	334 - Sullivan FERC # 2	4,185	60.00	-31.00	5.43	R2.5	18.42
25	335 - Faraday - FERC #2	258	55.00	-58.00	4.53	R0.5	22.08
26	335 - North Fork FERC #	867	55.00	-78.00	4.06	R0.5	24.63
27	335 - Oak Grove -FERC #	260	55.00	-57.00	4.21	R0.5	23.75
28	335 - Oak Grove Timothy	35	55.00	-57.00	4.21	R0.5	23.75
29	335 - Pelton Proj - FER	227	55.00	-176.00	4.65	R0.5	21.51
30	335 - River Mill FERC #	20	55.00	-101.00	3.71	R0.5	26.95
31	335 - Round Butte Plant	776	55.00	-78.00	4.06	R0.5	24.63
32	335 - Sullivan FERC # 2	109	55.00	-31.00	6.00	R0.5	16.67
33	336 - Faraday - FERC #2	2,342	75.00	-58.00	3.20	R1.5	31.25
34	336 - North Fork FERC #	2,768	75.00	-78.00	3.29	R1.5	30.40
35	336 - Oak Grove -FERC #	3,465	75.00	-57.00	4.19	R1.5	23.87
36	336 - Oak Grove Timothy	391	75.00	-57.00	4.19	R1.5	23.87
37	336 - Pelton Proj - FER	2,291	75.00	-176.00	3.20	R1.5	31.25
38	336 - River Mill FERC #	422	75.00	-101.00	3.11	R1.5	32.15
39	336 - Round Butte Plant	1,685	75.00	-78.00	3.36	R1.5	29.76
40	337 - ARC HYDRO	5				SQ	
41	341 - Beaver Plant:0440	36,697	70.00	-6.00	7.05	R3	14.18
42	341 - Biglow Canyon Win	34,859	40.00	-8.00	3.22	R4	31.06
43	341 - Carty Generating	73,365	70.00	-7.00	2.29	R3	43.67
44	341 - Coyote Springs	10,789	70.00	-5.00	4.29	R3	23.31
45	341 - Coyote Springs -	45	70.00	-5.00	4.29	R3	23.31
46	341 - Coyote Springs Co	888	70.00	-5.00	4.29	R3	23.31
47	341 - Port Westward	42,597	70.00	-7.00	3.08	R3	32.47
48	341 - Port Westward 2:	42,352	70.00	-7.00	2.33	R3	42.92
49	341 - Tucannon Wind Fac	18,334	40.00	-7.00	2.61	R4	38.31
50	342 - Beaver Plant:0440	63,000	50.00	-6.00	7.76	R3	12.89

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	342 - Carty Generating	74,983	48.00	-7.00	2.44	R3	40.98
13	342 - Coyote Springs	35,935	50.00	-5.00	4.69	R3	21.32
14	342 - Coyote Springs -	971	50.00	-5.00	4.69	R3	21.32
15	342 - KB Natural Gas Pi	4,152	50.00	-10.00	7.29	R3	13.72
16	342 - KB Pipeline Washi	16,823	50.00	-10.00	7.29	R3	13.72
17	342 - Port Westward	9,860	50.00	-7.00	3.35	R3	29.85
18	342 - Port Westward 2:	5,388	50.00	-7.00	2.46	R3	40.65
19	344 - Beaver Plant:0440	113,418	42.00	-6.00	7.83	R1.5	12.77
20	344 - Beaver Unit 8 Pla	675	42.00	-6.00	7.83	R1.5	12.77
21	344 - Biglow Canyon Win	869,315	30.00	-8.00	4.84	R3	20.66
22	344 - Carty Generating	377,821	38.00	-7.00	2.82	R2	35.46
23	344 - Coyote Springs	137,313	42.00	-5.00	5.31	R1.5	18.83
24	344 - Coyote Springs -	-2,953	42.00	-5.00	5.31	R1.5	18.83
25	344 - Coyote Springs Co	410	42.00	-5.00	5.31	R1.5	18.83
26	344 - Port Westward	201,816	42.00	-7.00	4.21	R1.5	23.75
27	344 - Port Westward 2:	220,368	42.00	-7.00	2.82	R1.5	35.46
28	344 - Solar - Sunway 1	1,072	20.00	-2.00	5.13	L2.5	19.49
29	344 - Solar - Sunway 2	426	20.00	-2.00	5.13	L2.5	19.49
30	344 - Solar Project	2,228	20.00	-2.00	5.13	L2.5	19.49
31	344 - Tucannon Wind Fac	445,046	30.00	-7.00	3.51	R3	28.49
32	345 - Beaver Plant:0440	26,831	45.00	-6.00	7.54	R2.5	13.26
33	345 - Biglow Canyon Win	27,385	30.00	-8.00	4.85	R2.5	20.62
34	345 - Coyote Springs	11,471	45.00	-5.00	5.08	R2.5	19.69
35	345 - Coyote Springs -	-230	45.00	-5.00	5.08	R2.5	19.69
36	345 - Coyote Springs Co	801	45.00	-5.00	5.08	R2.5	19.69
37	345 - Dispatchable Gene	13,861	45.00	-5.00	3.07	R2.5	32.57
38	345 - Port Westward	8,949	45.00	-7.00	3.68	R2.5	27.17
39	345 - Port Westward 2:	17,168	45.00	-7.00	2.61	R2.5	38.31
40	345 - Tucannon Wind Fac	14,668	30.00	-7.00	3.50	R2.5	28.57
41	346 - Beaver Plant:0440	4,349	55.00	-6.00	7.32	R2.5	13.66
42	346 - Biglow Canyon Win	1,324	40.00	-8.00	3.58	R2.5	27.93
43	346 - Carty Generating	4,621	55.00	-7.00	2.42	R2.5	41.32
44	346 - Coyote Springs	2,061	55.00	-5.00	4.53	R2.5	22.08
45	346 - Coyote Springs -	1,262	55.00	-5.00	4.53	R2.5	22.08
46	346 - Coyote Springs Co	129	55.00	-5.00	4.53	R2.5	22.08
47	346 - KB Natural Gas P	94	55.00	-5.00	7.29	R2.5	13.72
48	346 - Port Westward	3,287	55.00	-7.00	3.38	R2.5	29.59
49	346 - Port Westward 2:	3,201	55.00	-7.00	2.46	R2.5	40.65
50	346 - Tucannon Wind Fac	535	40.00	-7.00	2.69	R2.5	37.17

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	347 - ARC OTHER	16,698				SQ	
13	352 - Structures and im	25,881	65.00	-15.00	2.41	R2.5	41.49
14	353 - Station equipment	362,707	57.00	-15.00	2.77	R2	36.10
15	353 - Station equipment	7,965	57.00	-15.00	50.00	Life Span 2020	2.00
16	354 - Towers and fixtur	48,814	70.00	-10.00	3.23	S3	30.96
17	355 - Poles and fixture	38,517	50.00	-45.00	3.34	R1	29.94
18	356 - Overhead conducto	87,872	65.00	-15.00	2.13	R2.5	46.95
19	359 - Roads and trails	286	65.00		3.12	R3	32.05
20	359.1 ARC	34				SQ	
21	361 - Structures and im	48,372	65.00	-25.00	2.52	R2	39.68
22	362 - Station equipment	615,694	55.00	-20.00	3.20	S0	31.25
23	363 - Storage Battery E	385	15.00	-5.00	9.27	L3	10.79
24	364 - Poles, towers and	433,214	48.00	-45.00	3.77	R0.5	26.53
25	365 - Overhead conducto	692,225	50.00	-70.00	3.33	S0.5	30.03
26	366 - UNDERGROUND	24,484	80.00	-10.00	2.08	R4	48.08
27	367 - Undergrnd conduct	819,262	55.00	-70.00	2.81	S1.5	35.59
28	368 - Line transformers	443,797	50.00	-10.00	3.03	R2.5	33.00
29	369.1 - Unlicensed	76,840	48.00	-30.00	3.03	R2	33.00
30	369.3 - Unlicensed	392,901	50.00	-30.00	2.74	R4	36.50
31	370-Unlicensed	4,436	29.00	-10.00	6.17	R2	16.21
32	370.1 - AMI METERS	156,044	16.00	-10.00	9.96	S2.5	10.04
33	370.2 - RETAINED	7,033	16.00	-10.00	14.19	L0.5	7.05
34	371 - Unlicensed	376	30.00		6.92	R4	14.45
35	373.1 - Unlicensed	23,589	40.00	-27.00	4.32	L2.5	23.15
36	373.2 - Unlicensed	65,343	25.00	-27.00	6.57	L1	15.22
37	373.7 - Unlicensed	8,780	29.00	-27.00	6.29	L0.5	15.90
38	374 - ARC	477				SQ	
39	390. - BUILDINGS - STRU	104,216	40.00	-5.00	4.93	R0.5	20.28
40	390 - WTC	28,569	40.00		3.25	SQ	30.77
41	390.1 - Equipment - Str	4,158	40.00	-5.00	4.93	R0.5	20.28
42	390.2 - Land Improvemen	2,531	40.00	-5.00	4.93	R0.5	20.28
43	390.3 - Information Sys	1,141	40.00	-5.00	4.93	R0.5	20.28
44	391 - BOARDMAN	77	15.00		50.00	Life Span - 2020	2.00
45	391 - Colstrip	25	15.00		8.33	Life Span - 2030	12.00
46	391.1 - Office Furnitur	26,308	15.00		10.20	SQ	9.80
47	391.2 - COMP & OFF	169	5.00		50.00	Life Span - 2020	2.00
48	391.2 - Computer & Offi	126,205	5.00		32.97	SQ	3.03
49	392.4 - BOARDMAN	681	20.00	8.00	50.00	Life Span - 2020	2.00
50	392.4 - COLSTRIP	109	20.00	8.00	8.33	Life Span - 2030	12.00

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	392.4 - Heavy Duty Truc	23,027	20.00	8.00	6.30	S2	15.87
13	392.5 - BOARDMAN	337	16.00	8.00	50.00	Life Span - 2020	2.00
14	392.5 - COLSTRIP	54	16.00	8.00	8.33	Life Span - 2030	12.00
15	392.5 - Med Duty Truck	31,797	16.00	8.00	10.12	S1.5	9.88
16	392.6 - BOARDMAN	616	13.00	8.00	50.00	Life Span - 2020	2.00
17	392.6 - COLSTRIP	130	13.00	8.00	8.33	Life Span - 2030	12.00
18	392.6 - Lt Duty Truck	10,734	13.00	8.00	11.50	L2.5	8.70
19	392.8 - BOARDMAN	32	30.00	8.00	50.00	Life Span - 2020	2.00
20	392.8 - COLSTRIP	14	30.00	8.00	8.33	Life Span - 2030	12.00
21	392.8 - Trailer	6,077	30.00	8.00	5.69	S0	17.57
22	392.9 - Automobile	1,702	11.00	8.00	18.61	S1.5	5.37
23	392.9 - BOARDMAN	12	11.00	8.00	50.00	Life Span - 2020	2.00
24	392.9 - COLSTRIP	24	11.00	8.00	8.33	Life Span - 2030	12.00
25	3921. - Helicopter	2,703	20.00	8.00	8.24	S4	12.14
26	393 - Stores Equipment	1,143	20.00		9.49	SQ	10.54
27	393.1 - Forklifts	2,561	20.00		9.49	SQ	10.54
28	393.1 - Forklifts -	72	20.00		50.00	Life Span - 2020	2.00
29	394 - Boardman	998	20.00		50.00	Life Span - 2020	2.00
30	394 - Colstrip	95	20.00		8.33	Life Span - 2030	12.00
31	394 - Tool, Shop & Gara	20,295	20.00		8.15	SQ	12.27
32	395 - Lab Equipment - B	257	15.00		50.00	Life Span - 2020	2.00
33	395 - Laboratory Equipm	9,228	15.00		20.26	SQ	4.94
34	396.1 - Man Lift	19,490	14.00	10.00	12.51	S1.5	7.99
35	396.2 - BOARDMAN	810	16.00	10.00	50.00	Life Span - 2020	2.00
36	396.2 - Digger	4,505	16.00	10.00	10.81	R2.5	9.25
37	396.3 - BOARDMAN	189	22.00	10.00	50.00	Life Span - 2020	2.00
38	396.3 - COLSTRIP	47	22.00	10.00	8.33	Life Span - 2030	12.00
39	396.3 - Crane	4,757	22.00	10.00	7.62	S2.5	13.12
40	396.7 - BOARDMAN	1,120	19.00	10.00	50.00	Life Span - 2020	2.00
41	396.7 - COLSTRIP	126	19.00	10.00	8.33	Life Span - 2030	12.00
42	396.7 - Construction Eq	5,566	19.00	10.00	8.50	L1.5	11.76
43	397.1 - Unlicensed	16,063	15.00		8.16	SQ	12.25
44	397.3 - BOARDMAN	453	15.00		50.00	Life Span - 2020	2.00
45	397.3 - COLSTRIP -	3,695	15.00		8.33	Life Span - 2030	12.00
46	397.3 - Unlicensed	130,746	15.00		13.50	SQ	7.41
47	397.6 - Unlicensed	2,460	15.00		8.33	SQ	12.00
48	397.7 - Boardman	1	15.00		50.00	Life Span - 2020	2.00
49	397.7 - Unlicensed	889	15.00		9.48	SQ	10.55
50	398 - Unlicensed	1,035	20.00		5.63	SQ	17.76

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	399.1 - ARC GENERAL	65				SQ	
13							
14	Plant balance as of						
15	YE 2018 original cost.						
16							
17	Applied depreciation						
18	rates for all assets						
19	effective 1/1/2018 per						
20	Order 17-365 in						
21	OPUC Docket UM-1809.						
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
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Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/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		238,406	238,406	
2	Docket RM06-16				
3					
4	FERC-NERC Reliability		201,465	201,465	
5	Docket RM06-22				
6					
7	FERC matters less than $25,000		6,537	6,537	
8					
9	OPUC Docket UM 1805		48,452	48,452	
10					
11	OPUC Docket UM 1854		35,225	35,225	
12					
13	OPUC Docket UM 1931		239,209	239,209	
14					
15	OPUC Docket UM 1902		50,413	50,413	
16					
17	OPUC Docket EL18-109		32,187	32,187	
18					
19	OPUC Docket UE-335		296,473	296,473	
20					
21	OPUC matters less than $25,000		280,830	280,830	
22					
23	Unassigned Non Doc matters		670,630	670,630	
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL		2,099,827	2,099,827	

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	238,406					1
							2
							3
	928	201,465					4
							5
							6
	928	6,537					7
							8
	928	48,452					9
							10
	928	35,225					11
							12
	928	239,209					13
							14
	928	50,413					15
							16
	928	32,187					17
							18
	928	296,473					19
							20
	928	280,830					21
							22
	928	670,630					23
							24
							25
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							35
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							40
							41
							42
							43
							44
							45
		2,099,827					46

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

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

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

Line No.	Classification (a)	Description (b)
1	A(1)	Electric R, D & D Performed Internally - Generation
2	A(1)(d)	Nuclear
3	A(1)(e)	Unconventional Generation
4	A(2)	Electric R, D & D Performed Internally - Transmission
5	A(3)	Electric R, D & D Performed Internally - Distribution
6	A(5)	Electric R, D & D Performed Internally - Environment
7	A(6)	Electric R, D & D Performed Internally - Other
8	B(1)	Electric R, D & D Performed Externally
9		
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14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24	Totals	
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
538,510		930.2	538,510		4
259,761		930.2	259,761		5
80,466		930.2	80,466		6
79,288		930.2	79,288		7
	1,025,056	930.2	1,025,056		8
					9
					10
					11
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					21
					22
					23
958,025	1,025,056		1,983,081		24
					25
					26
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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	31,897,377		
4	Transmission	5,367,560		
5	Regional Market			
6	Distribution	15,840,716		
7	Customer Accounts	29,044,331		
8	Customer Service and Informational	6,827,068		
9	Sales			
10	Administrative and General	41,553,546		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	130,530,598		
12	Maintenance			
13	Production	12,340,488		
14	Transmission	1,232,090		
15	Regional Market			
16	Distribution	22,124,499		
17	Administrative and General	1,181,676		
18	TOTAL Maintenance (Total of lines 13 thru 17)	36,878,753		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	44,237,865		
21	Transmission (Enter Total of lines 4 and 14)	6,599,650		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	37,965,215		
24	Customer Accounts (Transcribe from line 7)	29,044,331		
25	Customer Service and Informational (Transcribe from line 8)	6,827,068		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	42,735,222		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	167,409,351	20,458,335	187,867,686
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)	167,409,351	20,458,335	187,867,686
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	104,901,023	5,371,578	110,272,601
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	104,901,023	5,371,578	110,272,601
72	Plant Removal (By Utility Departments)			
73	Electric Plant	331,389	15,004	346,393
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	331,389	15,004	346,393
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	1,612,158	135,588	1,747,746
79	Co-Owner Shares of Generating Facilities	5,104,228	182,340	5,286,568
80	Other	573,349	4,518,612	5,091,961
81	Payroll Allocated	30,681,457	-30,681,457	
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	37,971,192	-25,844,917	12,126,275
96	TOTAL SALARIES AND WAGES	310,612,955		310,612,955

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 2018/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 2018/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)	1,447,263	1,049,203	8,006,771	25,654,093
3	Net Sales (Account 447)	18,692,163	12,957,074	24,834,611	76,808,261
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
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42					
43					
44					
45					
46	TOTAL	20,139,426	14,006,277	32,841,382	102,462,354

Schedule Page: 397   Line No.: 2   Column: e

Represents purchases with ISO, netted by settlement invoice period and market.

Schedule Page: 397   Line No.: 3   Column: e

Represents sales with ISO, netted by settlement invoice period and market.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	189,353	MW	14,531,687	6,261,718	Various	157,793
2	Reactive Supply and Voltage				3,868,994	Various	125,897
3	Regulation and Frequency Response				3,868,922	Various	280,565
4	Energy Imbalance	8,090	MWh	1,132,332	12,332	MWh	1,995,300
5	Operating Reserve - Spinning				1,879,709	MWh	316,038
6	Operating Reserve - Supplement				1,879,709	MWh	316,038
7	Other						
8	Total (Lines 1 thru 7)	197,443		15,664,019	17,771,384		3,191,631

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

Scheduling, System Control and Dispatch	**No. of Units**	**Amount**
MW Day	1,615	83
MW Hour	120,915	2,807
MW Month	112	1,399
MW Year	2,270,266	114,816
Sum of Peak Demand (KW)	3,868,810	38,688
	6,261,718	157,793

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

Reactive Supply and Voltage	**No. of Units**	**Amount**
MW Month	112	4,301
MW Year	72	5,532
Sum of Peak Demand (KW)	3,868,810	116,064
	3,868,994	125,897

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

Regulation and Frequency Response	**No. of Units**	**Amount**
MW Month	112	9,748
Sum of Peak Demand (KW)	3,868,810	270,817
	3,868,922	280,565

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	1,879,709	316,038

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

Operating Reserve - Supplement	**No. of Units**	**Amount**
MW Month	1,879,709	316,038

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.

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	Monthly Peak MW - Total	Day of Monthly Peak	Hour of Monthly Peak	Firm Network Service for Self	Firm Network Service for Others	Long-Term Firm Point-to-point Reservations	Other Long-Term Firm Service	Short-Term Firm Point-to-point Reservation	Other Service
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	January	4,576	2	1800	3,032	260	2,329	74	3,857	32
2	February	4,579	21	1900	2,985	268	2,329	68	3,857	82
3	March	4,366	23	1900	2,566	251	2,329	59	3,857	38
4	Total for Quarter 1				8,583	779	6,987	201	11,571	152
5	April	4,139	3	900	2,684	269	2,329	57	3,857	267
6	May	4,339	14	1900	2,757	289	2,329	74	3,857	265
7	June	4,822	20	1800	3,212	307	2,329	73	4,691	237
8	Total for Quarter 2				8,653	865	6,987	204	12,405	769
9	July	5,400	30	1700	3,381	316	2,329	89	4,611	679
10	August	4,823	9	1900	3,492	311	2,329	85	4,603	72
11	September	4,545	5	1900	2,805	292	2,329	70	3,836	157
12	Total for Quarter 3				9,678	919	6,987	244	13,050	908
13	October	3,846	15	1100	2,153	264	2,329	53	3,836	35
14	November	4,095	28	1800	2,612	258	2,329	52	3,857	273
15	December	4,354	4	1900	2,908	260	2,344	80	3,857	82
16	Total for Quarter 4				7,673	782	7,002	185	11,550	390
17	Total Year to Date/Year				34,587	3,345	27,963	834	48,576	2,219

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	289	8	2300			307			
2	February	291	13	2300			307			
3	March	297	30	800			307			
4	Total for Quarter 1						921			
5	April	265	22	1300			307			
6	May	240	3	1800			307			
7	June	253	24	1400			307			
8	Total for Quarter 2						921			
9	July	273	25	800			307			
10	August	263	6	1300			307			
11	September	286	29	600			307			
12	Total for Quarter 3						921			
13	October	291	13	200			307			
14	November	291	14	1200			307			
15	December	285	4	2200			307			
16	Total for Quarter 4						921			
17	Total Year to Date/Year						3,684			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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									

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	17,186,002
3	Steam	3,106,183	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,690,990
5	Hydro-Conventional	1,473,691	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	26,450
7	Other	9,390,790	27	Total Energy Losses	654,470
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	22,557,912
9	Net Generation (Enter Total of lines 3 through 8)	13,970,664			
10	Purchases	9,002,682			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	6,669,093			
17	Delivered	7,084,527			
18	Net Transmission for Other (Line 16 minus line 17)	-415,434			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	22,557,912			

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	2,019,495	335,454	3,281	2	19
30	February	1,833,938	289,153	3,399	23	8
31	March	1,881,332	334,353	3,082	6	8
32	April	1,798,681	387,868	2,955	3	8
33	May	1,749,497	337,372	3,041	14	19
34	June	1,822,395	440,750	3,513	20	17
35	July	2,160,941	491,684	3,793	16	18
36	August	2,167,791	556,912	3,816	9	18
37	September	1,979,887	636,814	3,133	5	18
38	October	1,672,162	265,526	2,628	30	19
39	November	1,817,768	310,405	3,007	13	19
40	December	2,069,459	355,100	3,267	6	19
41	TOTAL	22,973,346	4,741,391			

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

In addition to the generation from the Beaver, Port Westward 1, Port Westward 2, Coyote Springs, and Carty generation plants, as shown on page 403, and generation from PGE's solar generation facilities, as shown on page 410, Other Generation includes 1,875,329 megawatt hours of net wind energy from PGE's Biglow Canyon Wind Farm and Tucannon River Wind Farm.
Actual gross wind generation from the two wind farms was 1,884,560 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 12/31/2018: $932,059,208
Total installed capacity: 450 megawatts
Operations and maintenance expenses for 2018: $15,395,144

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

In-service production cost at 12/31/2018: $484,955,743
Total installed capacity: 267 megawatts
Operations and maintenance expenses for 2018: $11,548,450

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

PGE has ownership in a 5Mw storage battery (Salem Smart Power Center) with a FERC 101 Plant-in-service balance of $384,933 as of year end 2018, 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 2018 to FERC 584.1 - Operation of Energy Storage Equipment $137 and FERC 592.2 - Maintenance of Energy Storage Equipment $9,918. Line loss includes 1.25 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Boardman (b)	Plant Name: Boardman (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	578.00
6	Net Peak Demand on Plant - MW (60 minutes)	587	0
7	Plant Hours Connected to Load	3302	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	83	0
12	Net Generation, Exclusive of Plant Use - KWh	1397734000	1246217000
13	Cost of Plant: Land and Land Rights	939463	832853
14	Structures and Improvements	154184201	141558153
15	Equipment Costs	578091422	514034004
16	Asset Retirement Costs	50135025	45089017
17	Total Cost	783350111	701514027
18	Cost per KW of Installed Capacity (line 17/5) Including	1219.7915	1213.6921
19	Production Expenses: Oper, Supv, & Engr	2514913	2059892
20	Fuel	40196229	36146707
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	5506166	4798999
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	6921939	6256059
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	585162	472509
30	Maintenance of Structures	436652	385873
31	Maintenance of Boiler (or reactor) Plant	1045945	930291
32	Maintenance of Electric Plant	11500842	10170959
33	Maintenance of Misc Steam (or Nuclear) Plant	583723	517696
34	Total Production Expenses	69291571	61738985
35	Expenses per Net KWh	0.0496	0.0495

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	931455	7959	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8690	138800	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	41.458	99.689	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	42.384	90.135	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.439	15.462	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.029	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	11582.100	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 2018/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	1859966000
13	Cost of Plant: Land and Land Rights	0	3328862
14	Structures and Improvements	0	117208573
15	Equipment Costs	0	358366052
16	Asset Retirement Costs	0	22935683
17	Total Cost	0	501839170
18	Cost per KW of Installed Capacity (line 17/5) Including	0	1612.5937
19	Production Expenses: Oper, Supv, & Engr	0	209749
20	Fuel	0	28043199
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	2043389
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	2902844
27	Rents	0	42766
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	467468
30	Maintenance of Structures	0	607584
31	Maintenance of Boiler (or reactor) Plant	0	4562091
32	Maintenance of Electric Plant	0	331029
33	Maintenance of Misc Steam (or Nuclear) Plant	0	842675
34	Total Production Expenses	0	40052794
35	Expenses per Net KWh	0.0000	0.0215

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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
573.20			483.30			271.20			5
497			425			268			6
2708			7019			5936			7
0			0			0			8
533			421			270			9
0			0			0			10
50			27			30			11
487406000			2499295000			1406995000			12
24473			24473			0			13
36678815			42615121			11722282			14
218808056			234447225			187169183			15
3054511			231072			113193			16
258565855			277317891			199004658			17
451.0919			573.8007			733.7930			18
386409			822884			153459			19
12547234			74451209			18746763			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
2509013			2621798			1369240			25
2904943			1446654			751124			26
217035			28586			83256			27
0			0			0			28
861546			15390			4704			29
202963			63522			51841			30
0			0			0			31
5355246			7267839			6510274			32
556474			79247			26103			33
25540863			86797129			27696764			34
0.0524			0.0347			0.0197			35
Gas	Oil		Gas	Oil		Gas	Oil		36
Mcf's	Barrels		Mcf's	Barrels		Mcf's	Barrels		37
4903243	488	0	17718949	0	0	10680993	0	0	38
1019000	138690	0	1019000	138690	0	1019000	138690	0	39
1.667	81.661	0.000	3.627	0.000	0.000	1.316	0.000	0.000	40
2.548	106.107	0.000	4.202	0.000	0.000	1.755	0.000	0.000	41
2.500	18.250	0.000	4.122	0.000	0.000	1.722	0.000	0.000	42
0.026	0.000	0.000	0.030	0.000	0.000	0.013	0.000	0.000	43
10255.714	0.000	0.000	7226.900	0.000	0.000	7738.400	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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: *Port Westward 2* (d)	Plant Name: *Carty* (e)	Plant Name: (f)	Line No.
Reciprocating Engine	Gas & Steam Turbine		1
Outdoor	Outdoor		2
2014	2016		3
2014	2016		4
225.10	503.10	0.00	5
224	461	0	6
1699	7621	0	7
0	0	0	8
225	0	0	9
0	0	0	10
0	22	0	11
120247000	3000514000	0	12
0	0	0	13
42352389	73364561	0	14
246124636	457424745	0	15
647461	4556945	0	16
289124486	535346251	0	17
1284.4269	1064.0951	0	18
21043	399241	0	19
4938361	47044370	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
294342	2818316	0	25
1088679	1769208	0	26
33347	0	0	27
0	0	0	28
442	89492	0	29
3357	155247	0	30
0	0	0	31
1009916	9067223	0	32
111997	432577	0	33
7501484	61775674	0	34
0.0624	0.0206	0.0000	35

(d)			(e)			(f)			Line No.
Gas	Oil		Gas	Oil					36
Mcf's	Barrels		Mcf's	Barrels					37
1185152	0	0	20629471	0	0	0	0	0	38
1019000	138690	0	1019000	138690	0	0	0	0	39
1.931	0.000	0.000	1.296	0.000	0.000	0.000	0.000	0.000	40
4.167	0.000	0.000	2.280	0.000	0.000	0.000	0.000	0.000	41
4.088	0.000	0.000	2.237	0.000	0.000	0.000	0.000	0.000	42
0.041	0.000	0.000	0.016	0.000	0.000	0.000	0.000	0.000	43
10046.900	0.000	0.000	7008.500	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.

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, 2018, as appropriate. Details are reported in Page 402 col (b).

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. Talen 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: 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 used 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.

Schedule Page: 402.1 Line No.: 44 Column: d1

The Port Westward 2 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: 402.1 Line No.: 44 Column: e1

The Carty 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 2018/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. 2195 Plant Name: Faraday (b)	FERC Licensed Project No. 2195 Plant Name: North Fork (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River;Storage	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional;Outdoor	Outdoor
3	Year Originally Constructed	1907	1958
4	Year Last Unit was Installed	1958	1958
5	Total installed cap (Gen name plate Rating in MW)	36.81	50.25
6	Net Peak Demand on Plant-Megawatts (60 minutes)	48	56
7	Plant Hours Connect to Load	8,757	8,491
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	46	58
10	(b) Under the Most Adverse Oper Conditions	5	7
11	Average Number of Employees	55	0
12	Net Generation, Exclusive of Plant Use - Kwh	130,291,000	159,953,000
13	Cost of Plant		
14	Land and Land Rights	33,434	377,100
15	Structures and Improvements	6,986,415	9,070,502
16	Reservoirs, Dams, and Waterways	32,812,712	86,490,281
17	Equipment Costs	9,588,314	13,796,481
18	Roads, Railroads, and Bridges	2,342,099	2,767,794
19	Asset Retirement Costs	90	6
20	TOTAL cost (Total of 14 thru 19)	51,763,064	112,502,164
21	Cost per KW of Installed Capacity (line 20 / 5)	1,406.2229	2,238.8490
22	Production Expenses		
23	Operation Supervision and Engineering	350,723	15,170
24	Water for Power	66,230	52,064
25	Hydraulic Expenses	1,305,829	739,992
26	Electric Expenses	377,393	239,065
27	Misc Hydraulic Power Generation Expenses	1,007,868	448,875
28	Rents	122,681	57,052
29	Maintenance Supervision and Engineering	330,201	5,646
30	Maintenance of Structures	15,391	0
31	Maintenance of Reservoirs, Dams, and Waterways	2,511	7,458
32	Maintenance of Electric Plant	83,564	35,985
33	Maintenance of Misc Hydraulic Plant	388,744	179,786
34	Total Production Expenses (total 23 thru 33)	4,051,135	1,781,093
35	Expenses per net KWh	0.0311	0.0111

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2030 Plant Name: Pelton (100%) (b)	FERC Licensed Project No. 2030 Plant Name: Pelton (PGE %) (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)	110.20	73.47
6	Net Peak Demand on Plant-Megawatts (60 minutes)	106	0
7	Plant Hours Connect to Load	8,459	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	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	360,462,000	240,308,000
13	Cost of Plant		
14	Land and Land Rights	3,681,440	2,454,416
15	Structures and Improvements	9,285,834	6,200,391
16	Reservoirs, Dams, and Waterways	15,691,504	10,687,580
17	Equipment Costs	10,418,006	6,971,644
18	Roads, Railroads, and Bridges	3,405,950	2,291,137
19	Asset Retirement Costs	51	51
20	TOTAL cost (Total of 14 thru 19)	42,482,785	28,605,219
21	Cost per KW of Installed Capacity (line 20 / 5)	385.5062	389.3456
22	Production Expenses		
23	Operation Supervision and Engineering	327,323	264,383
24	Water for Power	165,865	93,834
25	Hydraulic Expenses	2,413,780	1,727,695
26	Electric Expenses	288,522	141,474
27	Misc Hydraulic Power Generation Expenses	555,359	303,924
28	Rents	31,616	4,373
29	Maintenance Supervision and Engineering	67,132	1,632
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	14,476	14,476
32	Maintenance of Electric Plant	155,425	69,443
33	Maintenance of Misc Hydraulic Plant	120,312	41,161
34	Total Production Expenses (total 23 thru 33)	4,139,810	2,662,395
35	Expenses per net KWh	0.0115	0.0111

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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: River Mill (d)	FERC Licensed Project No. 2195 Plant Name: Oak Grove (e)	FERC Licensed Project No. 2233 Plant Name: Sullivan (f)	Line No.
Run-of-River	Run-of-River	Run-of-River	1
Conventional	Conventional	Conventional	2
1911	1924	1895	3
1952	1931	1953	4
20.60	51.00	15.40	5
26	39	18	6
8,758	8,750	8,184	7
			8
25	44	18	9
4	19	7	10
0	5	1	11
88,015,000	181,503,000	116,804,000	12
			13
86,408	9,457	572,077	14
6,827,255	15,294,742	18,308,931	15
58,989,428	35,000,070	32,564,814	16
8,549,218	13,167,199	14,589,811	17
421,796	3,856,282	0	18
64	2,122	2,630	19
74,874,169	67,329,872	66,038,263	20
3,634.6684	1,320.1936	4,288.1989	21
			22
15,290	21,324	10,039	23
43,071	58,126	35,671	24
406,203	1,265,599	187,481	25
56,038	110,391	164,906	26
249,616	371,265	338,679	27
0	531,212	447	28
0	224,329	112	29
0	0	0	30
2,663	3,337	51,407	31
233,229	175,031	217,319	32
52,605	200,230	15,971	33
1,058,715	2,960,844	1,022,032	34
0.0120	0.0163	0.0088	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 2018/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 (100%) (d)	FERC Licensed Project No. 2030 Plant Name: Round Butte (PGE %) (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Storage	Storage		1
Conventional	Conventional		2
1964	1964		3
1964	1964		4
372.50	248.33	0.00	5
305	0	0	6
8,741	0	0	7
			8
345	0	0	9
192	0	0	10
44	0	0	11
835,225,500	556,817,000	0	12
			13
3,726,480	2,521,011	0	14
18,135,051	12,088,518	0	15
183,104,087	120,037,784	0	16
36,496,965	24,493,409	0	17
2,489,334	1,684,933	0	18
165	165	0	19
243,952,082	160,825,820	0	20
654.9049	647.6294	0.0000	21
			22
261,190	184,264	0	23
317,675	229,637	0	24
2,424,476	1,585,928	0	25
440,146	260,420	0	26
1,183,732	876,422	0	27
54,335	21,039	0	28
179,496	99,441	0	29
0	0	0	30
191,230	191,230	0	31
417,842	312,753	0	32
406,224	309,484	0	33
5,876,346	4,070,618	0	34
0.0070	0.0073	0.0000	35

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

Respondent is the principal owner (66.67% interest) and operator of the Pelton Plant. The other owner is the Confederated Tribes of the Warm Springs Reservation of Oregon. Reported here are 100% costs and plant statistics, including shared and non-shared costs.

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

Jointly owned. Installed capacity on line 5 represents 66.67% share. Details reported on page 406.1, column (b). Reported here are respondent’s 66.67% share of cost of plant, net generation and production expenses.

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

Respondent is the principal owner (66.67% interest) and operator of the Round Butte plant. The other owner is the Confederated Tribes of the Warm Springs Reservation of Oregon. Reported here are 100% costs and plant statistics, including shared and non-shared costs.

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

Jointly owned. Installed capacity on line 5 represents 66.67% share. Details reported on page 407.1, column (d). Reported here are respondent’s 66.67% share of cost of plant, net generation and production expenses.

Schedule Page: 406.1 Line No.: 11 Column: b

All employees are reported at the Round Butte Location, which includes Pelton. Round Butte and Pelton are considered one department, are in close geographic proximity and share one FERC license. Employees are assigned to projects between both locations as needed.

Schedule Page: 406.1 Line No.: 11 Column: d

All employees are reported at the Round Butte Location, which includes Pelton. Round Butte and Pelton are considered one department, are in close geographic proximity and share one FERC license. Employees are assigned to projects between both locations as needed.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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. 0 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 2018/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. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	7	133,799
2	Oregon Military Dept/A.F.R.C	2001	1.60	1.6	62	186,058
3	US Bank Corp Columbia Center	2001	6.89	6.2	698	488,057
4	Portland State University	2004	2.80	2.8	45	261,732
5	Oregon Military Joint Forces HQ	2005	1.60	1.6	55	191,439
6	Stimson Lumber	2005	0.57	0.5	16	159,546
7	FORTIX (ViaWest)	2005	9.00	8.0	1,426	629,142
8	Skyline	2005	2.00	1.8	27	201,526
9	Tri-Quint	2005	0.60	0.5	5	109,968
10	NCCWC- Filter Plant	2005	2.00	1.8	35	122,958
11	PCC Structurals	2005	1.00	0.9	34	113,874
12	Providence Portland Medical Center	2005	6.00	5.4	835	265,383
13	Salem Hospital	2006	8.00	7.2	993	269,108
14	Sunrise Water Authority Pump Station	2006	1.25	1.1	28	88,272
15	Providence Newberg Hospital	2006	1.50	1.4	86	156,833
16	Sungard DSG	2006	2.00	1.8	42	331,845
17	Kaiser Sunnyside Hospital	2007	4.50	4.1	436	352,752
18	Newberg Waste Water Treatment Plant	2008	2.00	1.8	31	154,458
19	Xerox Corp	2007	4.00	3.6	143	380,259
20	Newberg Water Treatment Plant	2007	1.00	0.9	18	78,159
21	MEMC (Solaicx)	2008	1.00	0.9		62,963
22	Solar World	2008	3.00	2.7	68	219,984
23	Oregon Dept of Admin Serv - Data Center	2010	2.60	2.3	76	277,254
24	Sanyo	2010	1.00	0.9	15	43,144
25	Sysco Foods	2010	2.00	1.8	35	184,779
26	Clackamas Intertie 2	2012	0.60	0.5	7	155,832
27	Dawson Creek	2012	0.80	0.7	12	95,706
28	Kaiser Westside Hospital	2012	4.00	3.6	298	408,830
29	North Plains Pump Station	2012	0.80	0.7	17	53,132
30	Oak Lodge Sanitary District	2012	2.00	1.8	45	229,144
31	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.50	1.4	19	284,255
32	Oregon State Hospital	2012	4.00	3.6	181	172,879
33	Portland Service Center	2012	0.50	0.5	12	322,856
34	Sandy Highschool	2012	1.25	1.1	26	179,894
35	TATA Communications - Hillsboro	2012	3.56	3.2	191	328,979
36	Tri-City Wastewater Treatment Plant	2012	2.50	2.3	44	161,695
37	TATA Communications - Portland	2013	6.60	5.4	71	612,983
38	City of Hillsboro Crandall Reservoir	2013	0.80	0.7	13	105,854
39	East County Courts	2013	1.50	1.4	54	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	35	229,875
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	15	263,782
2	Carver (Readiness Center) DSG	2014	2.00	1.8	155	818,635
3	Juvenile Justice Center	2014	0.75	0.7	5	171,380
4	Clackamas River Water DSG	2014	2.00	1.8	33	383,436
5	Joint Water Commission	2015	5.00	4.5	193	190,302
6	Wapato Jail	2015	1.50	1.4	5	416,991
7	McLane Foodservice	2016	1.50	1.4	25	181,242
8	ViaWest Brookwood	2016	8.25	7.3	1,238	267,411
9	World Trade Center	2017	3.20	2.9	312	724,657
10	Washington County Jail	2017	1.50	1.4	23	325,268
11	OHSU	2017	4.50	4.1	169	833,547
12	Solar	2014	6.52	6.5	2,455	2,228,317
13	Total					16,089,256
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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.
267,598			12,752	diesel-low s	1,735	1
116,286		5,123	36,706	diesel-low s	1,735	2
70,856		49,572	63,121	diesel-low s	1,716	3
93,476			18,444	diesel-low s	1,735	4
119,649			11,957	diesel-low s	1,735	5
282,382			30,017	diesel-low s	1,735	6
69,905		40,444	162,015	diesel-low s	1,746	7
100,763		7,500	7,250	diesel-low s	1,733	8
183,280		1,631	10,864	diesel-low s	1,742	9
61,479		5,248	11,404	diesel-low s	1,687	10
113,874		3,724	9,237	diesel-low s	1,604	11
44,231		17,057	24,449	diesel-low s	1,687	12
33,639		36,021	62,868	diesel-low s	1,745	13
70,618				diesel-low s	1,735	14
104,555		1,887	43,395	diesel-low s	1,699	15
165,923		4,540	28,137	diesel-low s	1,784	16
78,389			38,461	diesel-low s	1,735	17
77,229			8,938	diesel-low s	1,735	18
95,065		11,167	32,775	diesel-low s	1,800	19
78,159			31,869	diesel-low s	1,735	20
62,963			1,185	diesel-low s		21
73,328		3,538	17,338	diesel-low s	1,743	22
106,636			15,507	diesel-low s	1,735	23
43,144		2,413	18,344	diesel-low s	1,759	24
92,390		5,624	24,867	diesel-low s	1,721	25
259,720			9,271	diesel-low s	1,735	26
119,633			6,417	diesel-low s	1,735	27
102,208			12,507	diesel-low s	1,735	28
66,415		1,950	7,539	diesel-low s	1,821	29
114,572		4,218	12,958	diesel-low s	1,714	30
189,503		4,607	18,648	diesel-low s	1,694	31
43,220			125,663	diesel-low s	1,735	32
645,712		559	17,548	diesel-low s	1,936	33
143,915		2,021	19,414	diesel-low s	1,830	34
92,540		33,930	24,498	diesel-low s	1,750	35
64,678		4,921	17,958	diesel-low s	1,762	36
92,876			93,907	diesel-low s	1,735	37
132,318		2,841	3,693	diesel-low s	1,771	38
211,232		6,001	26,051	diesel-low s	1,743	39
162,234		1,638	3,998	diesel-low s	1,768	40
114,938		7,117	17,410	diesel-low s	1,608	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 2018/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			6,085	diesel-low s	1,735	1
409,318		24,004	77,864	diesel-low s	2,665	2
228,507			23,003	diesel-low s	1,735	3
191,718		4,161	5,257	diesel-low s	1,700	4
38,060		24,030	38,463	diesel-low s	1,451	5
277,994			817	diesel-low s		6
120,828		4,200	2,980	diesel-low s	1,761	7
32,413		39,022	35,839	diesel-low s	1,733	8
226,455		12,830	23,426	diesel-low s	1,727	9
216,845		18,150	54,167	diesel-low s	1,698	10
185,233		2,545	14,394	diesel-low s	1,769	11
341,871	869,391		19,031	solar		12
		394,234	1,440,706			13
						14
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	500KV LINES							
2	GRIZZLY	ROUND BUTTE	500.00	500.00	ST. TOWER	15.60		1
3	GRIZZLY	MALIN	500.00	500.00	ST. TOWER	178.50		1
4	JOHN DAY	GRIZZLY '1'	500.00	500.00				1
5	JOHN DAY	GRIZZLY '2'	500.00	500.00				1
6	MISCELLANEOUS	MISCELLANEOUS	500.00					
7	CARTY	GRASSLAND	500.00	500.00	ST. TOWER	0.75		
8	GRASSLAND	BPA SLATT	500.00	500.00	ST.TOWER	16.82		
9	BOARDMAN	GRASSLAND	500.00	500.00	ST. TOWER	0.94		1
10	COYOTE SPRINGS	BPA SLATT	500.00	500.00				2
11	COLSTRIP PROJECT:							
12	COLSTRIP SWYD.	BROADVIEW 'A'	500.00	500.00	ST. TOWER		112.30	1
13	COLSTRIP SWYD.	BROADVIEW 'B'	500.00	500.00	ST. TOWER		115.80	1
14	BROADVIEW SWYD.	TOWNSEND 'A'	500.00	500.00	ST. TOWER		133.40	1
15	BROADVIEW SWYD.	TOWNSEND 'B'	500.00	500.00	ST. TOWER		133.40	1
16	Colstrip Project Costs	Project Lines						
17	Tot 500KV Line Expenses							
18								
19	BIGLOW CANYON WF	JOHN DAY	230.00	230.00				1
20	TUCANNON WF	CENTRAL FERRY BPA	230.00	230.00	H-WOOD	20.70		1
21								
22	PELTON 230KV PROJECT							
23	PELTON	ROUND BUTTE	230.00	230.00	H-WOOD	7.87		1
24								
25	NON PROJECT 230KV:							
26	BETHEL	ROUND BUTTE	230.00	230.00	H-WOOD	54.24		1
27			230.00	230.00	ST. TOWER	44.46		1
28	ROUND BUTTE	BPA REDMOND	230.00	230.00	H-WOOD	23.58		1
29	BETHEL	BPA TIE (SANTIAM)	230.00	230.00	H-WOOD	3.64		1
30	BETHEL	McLOUGHLIN	230.00	230.00	H-WOOD	35.67		1
31	CARVER	GRESHAM	230.00	230.00	H-WOOD	7.17		1
32	McLOUGHLIN	CARVER #1	230.00	230.00	H-WOOD	4.95		1
33	McLOUGHLIN	CARVER #2	230.00	230.00	ST. MONOP	4.88		1
34	BPA KEELER	ST. MARY'S W.	230.00	230.00	H-WOOD	2.89		1
35			230.00	230.00	ST. TOWER	3.78		2
36					TOTAL	626.64	536.65	60

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	BLUE LAKE	TROUTDALE BPA #1	230.00	230.00	H-WOOD	0.80		1
2			230.00	230.00	ST. MONOP	0.58		1
3	BLUE LAKE	TROUTDALE BPA #2	230.00	230.00	ST. TOWER	1.53		1
4	BLUE LAKE	GRESHAM	230.00	230.00	ST. TOWER	6.15		1
5	PEARL BPA	SHERWOOD	230.00	230.00	ST. TOWER		4.72	2
6			230.00	230.00	ST. TOWER	0.16		1
7	GRESHAM	LINNEMAN	230.00	230.00	ST. TOWER	0.31		1
8	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER	11.51		1
9			230.00	230.00	H-TOWER	0.60		1
10								
11	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER		4.40	2
12	ST. MARY'S W.	MURRAYHILL	230.00	230.00	ST. TOWER	5.92		1
13	HORIZON	KEELER BPA	230.00	230.00	ST. MONOP	1.47		1
14	MURRAYHILL	SHERWOOD	230.00	230.00	ST. TOWER	5.68		2
15	PORT WESTWARD	TROJAN #1	230.00	230.00	ST. MONOP	18.78		1
16	PORT WESTWARD	TROJAN #2	230.00	230.00	ST. MONOP	9.39		1
17	TROJAN	ST. MARY'S W.	230.00	230.00	H-WOOD	0.10		1
18			230.00	230.00	ST. TOWER	15.83		1
19					ST.TOWER		32.20	1
20	TROJAN	RIVERGATE	230.00	230.00	ST. TOWER	32.20		2
21			230.00	230.00	ST. TOWER	2.88		2
22								
23	Tot Nonproj 230kv Costs							
24								
25	GRESHAM	TROUTDALE BPA	230.00	230.00	ST. TOWER		0.43	1
26	BOARDMAN	PPL DALREED	230.00	230.00	H-WOOD	16.76		1
27								
28	Tot 230KV LINE EXPENSES							
29	PROJECT 115 KV LINES							
30	FARADAY	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		1
31	NORTH FORK	FARADAY	115.00	115.00	H-WOOD	2.79		1
32	OAK GROVE	FARADAY	115.00	115.00	DC LATTICE	18.68		2
33	OAK GROVE	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		2
34			115.00	115.00	DC LATTICE	18.68		2
35	Tot 115KV LINE EXPENSES							
36					TOTAL	626.64	536.65	60

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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
								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		10,355,181	10,355,181					7
1780MCMACSR								8
1780MCMACSR		6,353,549	6,353,549					9
		3,624,934	3,624,934					10
								11
								12
								13
								14
								15
	1,194,326	43,101,062	44,295,388					16
				2,744,000	525,448	989,436	4,258,884	17
								18
		3,040,852	3,040,852					19
795KCMAAC		1,956,263	1,956,263					20
								21
								22
795MCMACSR	7,579	418,911	426,490					23
								24
								25
1272MCMACSR								26
1272MCMACSR								27
795MCMACSR								28
795MCMACSR								29
1272MCMACSR								30
1272MCMAAC								31
1272MCMAAC								32
1272MCMACSS								33
1590MCMACSRTW								34
1590MCMACSRTW								35
	10,552,540	175,490,378	186,042,918	3,199,841	614,922	1,068,382	4,883,145	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 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1780MCMACSR								1
1780MCMACSR								2
1272MCMACSS								3
1272MCMACSS								4
2388MCMAACTW								5
2388MCMAACTW								6
1272MCMAAC								7
1272MCMAAC								8
1780MCMACSR								9
								10
1272MCMAAC								11
1272MCMAAC								12
1272MCMACSS								13
1272MCMAAC								14
2156MCMACSS								15
2156MCMACSS								16
1272MCMAAC								17
1590MCMAAC								18
1590MCMAAC								19
1590MCMAAC								20
1272MCMACSR								21
								22
	8,863,277	83,364,637	92,227,914					23
								24
954KCMACSR								25
795KCMAAC		976,430	976,430					26
								27
				455,841	89,474	9,090	554,405	28
								29
795KCMACSR		867,996	867,996					30
556KCMACSR	120,302	621,351	741,653					31
250CU	12,477	503,937	516,414					32
795KCMACSR								33
250CU	22,295	876,302	898,597					34
						69,856	69,856	35
	10,552,540	175,490,378	186,042,918	3,199,841	614,922	1,068,382	4,883,145	36

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 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 is not reported here as BPA is owner/operator of this portion of the Transmission Line.

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

Jointly owned with Idaho Power Company. Total length is indicated. Costs are respondent's share.

Schedule Page: 422 Line No.: 10 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/operator of these Transmission Lines.

Schedule Page: 422 Line No.: 11 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.: 19 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.: 23 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.: 5 Column: a

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

Schedule Page: 422.1 Line No.: 25 Column: a

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

Schedule Page: 422.1 Line No.: 26 Column: a

Jointly owned with Idaho Power Company. Total length is indicated. Costs are respondent's share.

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	BLUE LAKE	TROUTDALE BPA #2	1.53	ST. TOWER		1	1
2	BLUE LAKE	GRESHAM	6.15	ST. TOWER		1	1
3							
4							
5							
6							
7							
8							
9							
10							
11							
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41							
42							
43							
44	TOTAL		7.68			2	2

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
1272	ACSS		230		3,591,142	3,591,142		7,182,284	1
1272	ACSS		230		7,594,391	7,594,391		15,188,782	2
									3
									4
									5
									6
									7
									8
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									41
									42
									43
					11,185,533	11,185,533		22,371,066	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	13.00	11.00	4.10
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(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	13.00	
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	Marquam, Portland, OR	Distrib./unattended	115.00	13.00	
39	McClain, Salem, OR	Distrib./unattended	57.00	13.00	
40	Meridian, near Tualatin, OR	Distrib./unattended	115.00	13.00	

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Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Middle Grove, near Middle Grove, OR	Distrib./unattended	115.00	13.00	
2	Midway, near Portland, OR	Distrib./unattended	115.00	13.00	
3	Mill Creek, near Salem, OR	Distrib./unattended	115.00	13.00	
4	Mobile sub No. 1, OR	Distrib./unattended	115.00	57.00	13.00
5	Mobile sub No. 2, OR	Distrib./unattended	115.00	57.00	13.00
6	Mobile Sub No. 3, OR	Distrib./unattended	115.00	57.00	12.50
7	Mobile Sub No. 4, OR	Distrib./unattended	115.00	57.00	13.00
8	Molalla, Molalla, OR	Distrib./unattended	57.00	13.00	
9	Mt. Angel, Mt. Angel, OR	Distrib./unattended	57.00	13.00	
10	Mt. Pleasant, Oregon City, OR	Distrib./unattended	115.00	13.00	
11	Multnomah, Portland, OR	Distrib./unattended	115.00	13.00	
12	Newberg, Newberg, OR	Distrib./unattended	115.00	13.00	
13	North Marion, near Woodburn, OR	Distrib./unattended	57.00	13.00	
14	North Plains, North Plains, OR	Distrib./unattended	57.00	13.00	
15	Northern, Portland, OR	Distrib./unattended	57.00	11.00	
16	Oak Hills, near Beaverton, OR	Distrib./unattended	115.00	13.00	
17	Oregon City - BPA, near Wilsonville, OR	Distrib./unattended	57.00		
18	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	57.00	13.00
19	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
20	Orient, near Gresham, OR	Distrib./unattended	57.00	13.00	
21	Oswego, Lake Oswego, OR	Distrib./unattended	115.00	13.00	
22	Oxford, Salem, OR	Distrib./unattended	115.00	13.00	
23	Peninsula Park, Portland, OR	Distrib./unattended	115.00	13.00	
24	Pleasant Valley, near Portland, OR	Distrib./unattended	115.00	12.50	
25	Portsmouth, Portland, OR	Distrib./unattended	115.00	13.00	
26	Progress, near Tigard, OR	Distrib./unattended	115.00	13.00	
27	Raleigh Hills, near Portland, OR	Distrib./unattended	115.00	13.00	
28	Ramapo, near Portland, OR	Distrib./unattended	115.00	13.00	
29	Redland, near Oregon City, OR	Distrib./unattended	115.00	13.00	
30	Reedville, near Beaverton, OR	Distrib./unattended	115.00	13.00	
31	Rhododendron Switching, OR	Distrib./unattended	57.00		
32	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	13.00	
33	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	11.00	
34	Riverview, Portland, OR	Distrib./unattended	115.00	13.00	
35	Rockwood, near Gresham, OR	Distrib./unattended	115.00	13.00	
36	Rosemont, near Lake Oswego, OR	Distrib./unattended	115.00	13.00	
37	Roseway, Hillsboro, OR	Distrib./unattended	115.00	13.00	
38	Ruby,Gresham, OR	Distrib./unattended	115.00	13.00	
39	Salem-PGE, near Salem, OR	Distrib./unattended	57.00	13.00	
40	Sandy, Sandy, OR	Distrib./unattended	57.00	13.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Scappoose, Scappoose, OR	Distrib./unattended	115.00		
2	Scholls Ferry, Beaverton, OR	Distrib./unattended	115.00	13.00	
3	Scoggin, near Gaston, OR	Distrib./unattended	57.00	13.00	
4	Sellwood, Portland, OR	Distrib./unattended	115.00	57.00	13.00
5	Sellwood, Portland, OR	Distrib./unattended	115.00	13.00	
6	Sheridan, Sheridan, OR	Distrib./unattended	57.00	13.00	
7	Shute, Hillsboro, OR	Distrib./unattended	115.00	34.50	
8	Silverton, Silverton, OR	Distrib./unattended	57.00	13.00	
9	Six Corners, Six Corners, OR	Distrib./unattended	115.00	13.00	
10	Springbrook, Newberg, OR	Distrib./unattended	115.00	13.00	
11	Springdale, near Springdale, OR	Distrib./unattended		12.50	
12	St. Helens, near St. Helens, OR	Distrib./unattended	115.00		
13	St. Johns-BPA, near Portland, OR	Distrib./unattended		11.00	
14	St. Louis, St. Louis, OR	Distrib./unattended	57.00	13.00	
15	St. Marys, East Yard, near Beaverton, OR	Distrib./unattended	115.00	13.00	
16	Stephens, Portland, OR	Distrib./unattended	57.00	11.00	
17	Sullivan, West Linn, OR	Distrib./unattended	115.00	13.00	
18	Summit, Government Camp, OR	Distrib./unattended	57.00	13.00	
19	Summit, Government Camp, OR	Distrib./unattended	24.00	13.00	
20	Sunset, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
21	Sunset, near Hillsboro, OR	Distrib./unattended	115.00	34.50	
22	Swan Island, Portland, OR	Distrib./unattended	115.00	13.00	
23	Sylvan, near Portland, OR	Distrib./unattended	115.00	13.00	
24	Tabor, Portland, OR	Distrib./unattended	115.00	13.00	
25	Tabor, Portland, OR	Distrib./unattended	57.00		
26	Tektronix, Beaverton, OR	Distrib./unattended	115.00	13.00	
27	Tigard, Tigard, OR	Distrib./unattended	115.00	12.50	
28	Town Center, Portland, OR	Distrib./unattended	115.00	13.00	
29	Tualitin, Tualitin, OR	Distrib./unattended	115.00	13.00	
30	Twilight, Canby, OR	Distrib./unattended	57.00	13.00	
31	University, Salem, OR	Distrib./unattended	115.00	13.00	
32	Urban, Portland, OR	Distrib./unattended	115.00	13.00	
33	Waconda, near Hopmere, OR	Distrib./unattended	57.00	12.50	
34	Wallace, Salem, OR	Distrib./unattended	115.00	13.00	
35	Welches, near Welches, OR	Distrib./unattended	57.00	24.00	
36	Welches, near Welches, OR	Distrib./unattended	57.00	13.00	
37	West Portland, Lower Yard, near Tigard, OR	Distrib./unattended	115.00		
38	West Portland, Upper Yard, near Tigard, OR	Distrib./unattended	115.00	13.00	
39	West Union, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
40	Willamina, near Willamina, 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 2018/Q4

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Willbridge, Portland, OR	Distrib./unattended	115.00	11.00	
2	Wilsonville, near Wilsonville, OR	Distrib./unattended	115.00	13.00	
3	Woodburn, Woodburn, OR	Distrib./unattended	57.00	13.00	
4	Yamhill, near Yamhill, OR	Distrib./unattended	57.00	13.00	
5					
6					
7					
8	Bakeoven, BPA, near Bakeoven, OR	Transm./unattended	500.00		
9	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	13.00	
10	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	24.00	
11	Bethel, Salem, OR	Transm./unattended	230.00	115.00	13.00
12	Bethel, Salem, OR	Transm./unattended	115.00	57.00	13.00
13	Bethel, Salem, OR	Transm./unattended	115.00	13.00	
14	Biglow Canyon Wind Farm, Wasco, OR	Transm./unattended	230.00	34.50	13.80
15	Blue Lake, Troutdale, OR	Transm./unattended	230.00	115.00	13.00
16	Blue Lake, Troutdale, OR	Transm./unattended	115.00	13.00	
17	Boardman, near Boardman, OR	Transm./unattended	500.00	24.00	
18	Boardman, OR	Transm./unattended	230.00	7.20	
19	Boardman, OR	Transm./unattended	24.00	7.20	
20	Broadview Subst. near Broadview, MT	Transm./unattended	500.00	230.00	
21	Buckley, BPA near Buckley, WA	Transm./unattended	500.00		
22	Captain Jack, BPA, near Malin, OR	Transm./unattended	500.00		
23	Carver, Carver, OR	Transm./unattended	230.00	115.00	13.00
24	Carver, Carver, OR	Transm./unattended	115.00	13.00	
25	Colstrip Plant, near Colstrip, MT	Transm./unattended	500.00	26.00	
26	Colstrip Subst. near Colstrip, MT	Transm./unattended	500.00	230.00	
27	Coyote Springs, Boardman, OR	Transm./unattended	500.00		
28	Faraday, Switchyard, near Estacada, OR	Transm./unattended	115.00	57.00	12.50
29	Faraday, Switchyard, near Estacada, OR	Transm./unattended	57.00	11.00	
30	Faraday Plant, near Estacada, OR	Transm./unattended	115.00	12.50	
31	Fort Rock, approx 12 mi NE of Silver Lake, OR	Transm./unattended	500.00		
32	Grassland, near Boardman, OR	Transm./unattended	500.00		
33	Gresham, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
34	Grizzly, BPA, near Madras, OR	Transm./unattended	500.00		
35	Horizon, Hillsboro, OR	Transm./unattended	230.00	115.00	13.00
36	Keeler, BPA, Hillsboro, OR				
37	Linneman, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
38	Malin, BPA, near Malin, OR	Transm./unattended	500.00		
39	McLoughlin, near Oregon City, OR	Transm./unattended	230.00	115.00	13.00
40	Monitor, near Monitor, OR	Transm./unattended	230.00	57.00	13.00

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Murrayhill, Beaverton, OR	Transm./unattended	230.00	115.00	13.00
2	Murrayhill, Beaverton, OR	Transm./unattended	115.00	13.00	
3	North Fork, near Estacada, OR	Transm./unattended	115.00	13.00	
4	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	13.00	
5	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	11.00	
6	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	11.00	
7	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	0.48	
8	Pearl, BPA, near Wilsonville, OR	Transm./unattended	230.00		
9	Pelton, near Madras, OR	Transm./unattended	230.00	13.00	
10	Pelton, near Madras, OR	Transm./unattended	13.00	13.00	
11	Port Westward, near Clatskanie, OR	Transm./unattended	230.00	18.00	16.50
12	River Mill, near Estacada, OR	Transm./unattended	57.00	11.00	
13	Rivergate North Yard, near Portland, OR	Transm./unattended	230.00	115.00	13.00
14	Round Butte, near Madras, OR	Transm./unattended	500.00	230.00	12.50
15	Round Butte, near Madras, OR	Transm./unattended	230.00	12.50	
16	Sand Springs, 22 mi E/22 mi S of Bend, OR	Transm./unattended	500.00		
17	Sherwood, near Six Corners, OR	Transm./unattended	230.00	115.00	13.00
18	Slatt, BPA, Arlington, OR	Transm./unattended	500.00		
19	St. Marys, West Yard, near Beaverton, OR	Transm./unattended	230.00	115.00	13.00
20	Sullivan, West Linn, OR	Transm./Unattended	57.00	4.15	
21	Sycan, 27 mi S of Silver Lake, OR	Transm./unattended	500.00		
22	Trojan, near Rainier, OR	Transm./unattended	230.00	12.50	
23	Troutdale, BPA near Troutdale OR	Transm./unattended	230.00		
24	Tucannon Mullan Switchyard, Dayton, WA	Transm./unattended	230.00	34.50	13.00
25	TOTAL MVa		30386.00	5024.03	383.90
26					
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38					
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SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (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
45	2		Capacitor Banks	2	12,000	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
28	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

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
56	2		Capacitor Banks	4	12,000	2
30	2		Capacitor Banks	2	3,600	3
25	1		Capacitor Banks	1	3,600	4
50	2		Capacitor Banks	1	3,000	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
25	1		Capacitor Banks	6	19,200	14
50	2		Capacitor Banks	4	12,000	15
28	1		Capacitor Banks	2	6,000	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	12,000	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
150	3		Capacitor Banks	10	54,000	38
23	3					39
84	3		Capacitor Banks	6	18,600	40

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
53	2		Capacitor Banks	4	12,000	1
34	2		Capacitor Banks	1	3,600	2
17	1		Capacitor Banks	2	6,000	3
15	1					4
34	1					5
29	1					6
34	1					7
42	2		Capacitor Banks	4	9,000	8
20	1		Capacitor Banks	3	15,000	9
45	2		Capacitor Banks			10
39	2		Capacitor Banks	3	9,600	11
45	2		Capacitor Banks	4	12,000	12
31	3		Capacitor Banks	3	15,000	13
20	1		Capacitor Banks	4	18,000	14
28	2					15
56	2		Capacitor Banks	4	14,400	16
						17
280	2					18
81	3		Capacitor Banks	6	18,600	19
28	1		Capacitor Banks	2	6,000	20
34	2		Capacitor Banks	2	7,200	21
50	2		Capacitor Banks	4	12,300	22
28	1		Capacitor Banks	2	6,000	23
56	2		Capacitor Banks	4	12,000	24
28	1					25
50	2		Capacitor Banks	4	13,800	26
28	1		Capacitor Banks	2	6,600	27
28	1		Capacitor Banks	2	6,000	28
22	1					29
84	3		Capacitor Banks	6	18,000	30
						31
22	1		Capacitor Banks	2	7,200	32
22	1		Capacitor Banks	2	6,716	33
28	1		Capacitor Banks	2	6,000	34
78	3		Capacitor Banks	5	15,000	35
28	1		Capacitor Banks	2	6,000	36
28	1		Capacitor Banks	2	6,000	37
28	1		Capacitor Banks	2	6,000	38
45	2		Capacitor Banks	4	12,000	39
28	1		Capacitor Banks	2	6,000	40

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
28	1		Capacitor Banks	2	6,000	2
13	2		Capacitor Banks	1	10,800	3
140	1		Capacitor Banks	1	24,000	4
28	1		Capacitor Banks	2	6,000	5
17	1		Capacitor Banks	3	19,200	6
100	2		capacitor Banks	4	18,000	7
33	3		Capacitor Banks	2	3,600	8
49	2		Capacitor Banks	2	6,000	9
56	2		Capacitor Banks	5	36,000	10
						11
			Capacitor Banks	1	24,000	12
						13
24	2		Capacitor Banks	2	7,200	14
56	2		Capacitor Banks	4	12,000	15
100	2		Capacitor Banks	2	16,800	16
45	2		Capacitor Banks	5	36,000	17
8	1	1				18
14	1					19
400	8		Capacitor Banks	25	150,000	20
375	3					21
53	2		Capacitor Banks	4	12,000	22
22	1		Capacitor Banks	2	6,000	23
22	1		Capacitor Banks	2	6,000	24
						25
84	3		Capacitor Banks	6	18,000	26
45	2		Capacitor Banks	4	12,000	27
56	2		Capacitor Banks	2	6,000	28
56	2		Capacitor Banks	4	13,200	29
28	1		Capacitor Banks	3	19,200	30
22	1		Capacitor Banks	2	7,200	31
112	4		Capacitor Banks	6	15,600	32
41	2		Capacitor Banks	2	6,000	33
28	1		Capacitor Banks	2	6,000	34
10	1		Capacitor Banks	1	12,000	35
18	2		Capacitor Banks	2	6,000	36
			Capacitor Banks	1	24,000	37
56	2		Capacitor Banks	4	13,200	38
56	2		Capacitor Banks	4	12,000	39
24	2		Capacitor Banks	3	7,800	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.
20	1					1
84	3		Capacitor Banks	6	18,000	2
42	2		Capacitor Banks	4	13,200	3
15	2		Capacitor Banks	1	1,800	4
						5
						6
						7
						8
464	4					9
170	1					10
564	2					11
140	1					12
28	1		Capacitor Banks	2	6,000	13
480	3					14
320	1					15
28	1		Capacitor Banks	2	6,000	16
685	3					17
55	1					18
55	1					19
80	3					20
						21
						22
640	2					23
56	2		Capacitor Banks	4	12,000	24
164	3					25
100	2					26
300	3					27
140	1					28
32	2					29
27	1					30
			Series Capacitor	1	363,000	31
						32
572	2					33
						34
640	2					35
						36
168	1					37
			Reactors	3	180,000	38
640	2					39
125	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)	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)	
320	1					1
56	2		Capacitor Banks	3	10,800	2
53	3	1				3
8	1					4
64	2					5
						6
						7
						8
164	4					9
3	1					10
450	3					11
32	2					12
520	4		Capacitor Banks	1	22,000	13
561	3		Reactors	12	180,000	14
394	4	2				15
			Series Capacitor	1	546,000	16
640	2					17
						18
960	3		Capacitor Banks	3	108,000	19
33	1					20
			Series Capacitor	1	546,000	21
56	2					22
						23
320	2		Capacitors/Reactors	6	90,000	24
19204	368	4		446	3,662,886	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.: 17 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.: 31 Column: a
Switching only.

Schedule Page: 426.3 Line No.: 1 Column: a
Switching only. Distribution owned by Columbia River PUD.

Schedule Page: 426.3 Line No.: 11 Column: a
Regulating only.

Schedule Page: 426.3 Line No.: 12 Column: a
Switching only. Distribution owned by Columbia River PUD.

Schedule Page: 426.3 Line No.: 13 Column: a
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.

Schedule Page: 426.3 Line No.: 25 Column: a
Switching only.

Schedule Page: 426.3 Line No.: 37 Column: a
Switching only.

Schedule Page: 426.4 Line No.: 8 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.: 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 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.: 19 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.: 20 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.: 21 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
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.: 25 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.: 26 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.: 27 Column: a

Contribution in aid of construction made to Bonneville Power Administration in 1995 and 2006 to FERC account 353.

Schedule Page: 426.4 Line No.: 31 Column: a

Line compensation only.

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

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

Schedule Page: 426.4 Line No.: 36 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.: 38 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.: 8 Column: a

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

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

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

Schedule Page: 426.5 Line No.: 10 Column: a

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

Schedule Page: 426.5 Line No.: 15 Column: a

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

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

Line compensation only.

Schedule Page: 426.5 Line No.: 18 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.: 21 Column: a

Line compensation only.

Schedule Page: 426.5 Line No.: 23 Column: a

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/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	4,650,724
4	OPUC Order No. 75-953			
5				
6	Catering Services	Salmon Springs Hospitality Group	921	718,759
7				
8				
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	1,218,923
23				
24				
25				
26				
27				
28				
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