e-FILING REPORT COVER SHEET

COMPANY NAME: Portland General Electric

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

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.

PGE's 2020 FERC Form 1; PGE's 2020 Oregon Supp to FERC Form 1; and PGE's 2020 Annual Report to Shareholders

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

**Portland General Electric Company**
121 SW Salmon Street • 1WTC0306 • Portland, OR 97204
portlandgeneral.com

April 30, 2021

*Via Electronic Mail*

Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

**RE: RE 54 PGE's 2020 Annual Report and 2020 FERC Form 1**

Dear Filing Center,

Enclosed for filing are PGE's 2020 Annual Report, and 2020 FERC Form 1. The e-filed portion of the filing includes:

- PGE's 2020 Annual Report and
- PGE's 2020 FERC Form 1

Sent on CDs via U.S. mail:

- Two CDs with the FERC Form as an excel workbook;
- Two CDs with the final pre-closing trial balance by FERC account;
- Two CDs with the Oregon Supplement to the FERC Annual Report; and
- One CD containing Distribution of Salaries and Wages and Final Pre-Closing Trial Balance by FERC Account.

Not included are five printed copies of PGE's 2020 Annual Report. PGE provides this information to Shareholders in electronic format only. The link to the Annual Report is provided below.

http://investors.portlandgeneral.com/financial-information/annual-reports

If you have any questions or require further information, please call me at 503-464-7488. Please direct all formal correspondence, questions, or requests to the following e-mail address: pge.opuc.filings@pgn.com.

Sincerely,

/s/ Jaki Ferchland
Jaki Ferchland
Manager, Revenue Requirement

JF/np
cc: Bryan Conway, OPUC

THIS FILING IS

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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

# 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** 2020/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: https://forms.ferc.gov/. 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 https://www.ferc.gov/ferc-online/overview.

(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 https://www.ferc.gov/media/form-1 and https://www.ferc.gov/media/form1-3q.

**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<br>Portland General Electric Company | 02 Year/Period of Report<br>End of 2020/Q4 |
| 03 Previous Name and Date of Change *(if name changed during year)*<br>/ / | |
| 04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)*<br>121 SW Salmon Street, Portland, Oregon, 97204 | |
| 05 Name of Contact Person<br>Christopher Liddle | 06 Title of Contact Person<br>Controller & Asst. Treasurer |
| 07 Address of Contact Person *(Street, City, State, Zip Code)*<br>121 SW Salmon Street, Portland, Oregon, 97204 | |

| | | |
|---|---|---|
| 08 Telephone of Contact Person, *Including Area Code*<br>(503) 464-7458 | 09 This Report Is<br>(1) [X] An Original (2) [ ] A Resubmission | 10 Date of Report *(Mo, Da, Yr)*<br>/ / |

## 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<br>James A. Ajello | 03 Signature<br>James A. Ajello | 04 Date Signed *(Mo, Da, Yr)*<br>04/16/2021 |
| 02 Title<br>SVP of Finance, CFO and Treasurer | | |

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

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

| Line No. | Title of Schedule (a) | Reference Page No. (b) | Remarks (c) |
|---|---|---|---|
| 37 | Other Deferred Credits | 269 | |
| 38 | Accumulated Deferred Income Taxes-Accelerated Amortization Property | 272-273 | |
| 39 | Accumulated Deferred Income Taxes-Other Property | 274-275 | |
| 40 | Accumulated Deferred Income Taxes-Other | 276-277 | |
| 41 | Other Regulatory Liabilities | 278 | |
| 42 | Electric Operating Revenues | 300-301 | |
| 43 | Regional Transmission Service Revenues (Account 457.1) | 302 | None |
| 44 | Sales of Electricity by Rate Schedules | 304 | |
| 45 | Sales for Resale | 310-311 | |
| 46 | Electric Operation and Maintenance Expenses | 320-323 | |
| 47 | Purchased Power | 326-327 | |
| 48 | Transmission of Electricity for Others | 328-330 | |
| 49 | Transmission of Electricity by ISO/RTOs | 331 | Not applicable |
| 50 | Transmission of Electricity by Others | 332 | |
| 51 | Miscellaneous General Expenses-Electric | 335 | |
| 52 | Depreciation and Amortization of Electric Plant | 336-337 | |
| 53 | Regulatory Commission Expenses | 350-351 | |
| 54 | Research, Development and Demonstration Activities | 352-353 | |
| 55 | Distribution of Salaries and Wages | 354-355 | |
| 56 | Common Utility Plant and Expenses | 356 | None |
| 57 | Amounts included in ISO/RTO Settlement Statements | 397 | |
| 58 | Purchase and Sale of Ancillary Services | 398 | |
| 59 | Monthly Transmission System Peak Load | 400 | |
| 60 | Monthly ISO/RTO Transmission System Peak Load | 400a | Not applicable |
| 61 | Electric Energy Account | 401 | |
| 62 | Monthly Peaks and Output | 401 | |
| 63 | Steam Electric Generating Plant Statistics | 402-403 | |
| 64 | Hydroelectric Generating Plant Statistics | 406-407 | |
| 65 | Pumped Storage Generating Plant Statistics | 408-409 | Not applicable |
| 66 | Generating Plant Statistics Pages | 410-411 | |

LIST OF SCHEDULES (Electric Utility) (continued)

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

| Line No. | Title of Schedule (a) | Reference Page No. (b) | Remarks (c) |
|---|---|---|---|
| 67 | Transmission Line Statistics Pages | 422-423 | |
| 68 | Transmission Lines Added During the Year | 424-425 | |
| 69 | Substations | 426-427 | |
| 70 | Transactions with Associated (Affiliated) Companies | 429 | |
| 71 | Footnote Data | 450 | |
| | Stockholders' Reports Check appropriate box:<br>[X] Two copies will be submitted<br>[ ] 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.

Christopher Liddle
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

## 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 Corporation | 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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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 | 971,710 |
| 2 | | | |
| 3 | Senior Vice President of Finance, Chief Financial | James F. Lobdell | 544,227 |
| 4 | Officer and Treasurer | | |
| 5 | | | |
| 6 | Vice President, General Counsel and Corporate | Lisa A. Kaner | 412,469 |
| 7 | Compliance Officer | | |
| 8 | | | |
| 9 | Vice President Strategy Regulation & Energy Supply | Brett Sims | 297,822 |
| 10 | | | |
| 11 | Vice President, Public Policy | W. David Robertson | 348,211 |
| 12 | | | |
| 13 | Vice President, Chief Customer Officer | John McFarland | 317,225 |
| 14 | | | |
| 15 | Vice President, Utility Operations | Bradley Y. Jenkins | 388,153 |
| 16 | | | |
| 17 | Vice President, Grid Architecture, Integration & | Larry N. Bekkedahl | 390,608 |
| 18 | Systems Operations | | |
| 19 | | | |
| 20 | Vice President, Information Technology and Chief | John Kochavatr | 377,601 |
| 21 | Information Officer | | |
| 22 | | | |
| 23 | Vice President, Operations Services | Kristin A. Stathis | 333,185 |
| 24 | | | |
| 25 | Vice President, Human Resources, Diversity, | Anne E. Mersereau | 352,187 |
| 26 | Equity & Inclusion | | |
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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<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

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

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

***Schedule Page: 104 Line No.: 3 Column: b***

Retired from company effective December 31, 2020.

***Schedule Page: 104 Line No.: 9 Column: b***

Appointed Vice President on October 30, 2020.

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 | Managing Partner, Cascadia Law Group PLLC | |
| 6 | | |
| 7 | Jack E. Davis | Santa Fe, New Mexico |
| 8 | Chair of the Board, Portland General Electric | |
| 9 | Retired Chief Executive Officer, Arizona Public Service Co. | |
| 10 | | |
| 11 | Kirby A. Dyess | Beaverton, Oregon |
| 12 | Principal, Austin Capital Management LLC | |
| 13 | | |
| 14 | Mark B. Ganz | Portland, Oregon |
| 15 | Retired President and Chief Executive Officer, | |
| 16 | Cambia Health Soluntions, Inc. | |
| 17 | | |
| 18 | Kathryn J. Jackson | Cincinnati, Ohio |
| 19 | Director, Energy & Technology Consulting, KeySource, Inc. | |
| 20 | | |
| 21 | Neil J. Nelson | Keizer, Oregon |
| 22 | Retired President and Chief Executive Officer, | |
| 23 | Siltronic Corp. | |
| 24 | | |
| 25 | M. Lee Pelton | Boston, Massachusetts |
| 26 | President, Emerson College | |
| 27 | | |
| 28 | Maria M. Pope | Portland, Oregon |
| 29 | President and Chief Executive Officer, | |
| 30 | Portland General Electric | |
| 31 | | |
| 32 | Charles W. Shivery | Longboat Key, Florida |
| 33 | Retired President and Chief Executive Officer, | |
| 34 | Northeast Utilities | |
| 35 | | |
| 36 | Marie Oh Huber | San Jose, California |
| 37 | Sr. VP, Chief Legal Officer, General Counsel | |
| 38 | and Secretary, eBay Inc | |
| 39 | | |
| 40 | Michael H. Millegan | Kirkland, Washington |
| 41 | Founder and Chief Executive Officer, | |
| 42 | Millegan Advisory Group 3 LLC | |
| 43 | | |
| 44 | Michael L. Lewis | Bethesda, Maryland |
| 45 | Retired Interim President of Pacific Gas and Electric Co. | |
| 46 | | |
| 47 | James P. Torgerson | Brandford, Connecticut |
| 48 | Retired Chief Executive Officer, AVENGRID, Inc. | |

| Name of Respondent | This Report is: | Date of Report | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | (Mo, Da, Yr)<br>/ / | 2020/Q4 |

FOOTNOTE DATA

**_Schedule Page: 105 Line No.: 44 Column: a_**

Appointed to the Board effective January 1, 2021.

**_Schedule Page: 105 Line No.: 47 Column: a_**

Appointed to the Board effective January 1, 2021.

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

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[ ] Yes
[X] No

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

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

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

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

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

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

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

| Name of Respondent | This Report is: | Date of Report | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | (Mo, Da, Yr)<br>/ / | 2020/Q4 |

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None

2. None

3. None

4. None

5. None

6. Pursuant to PGE's application, the FERC, on January 16, 2020, issued an order in Docket No. ES20-7-000 that authorizes the Company to issue up to $900 million of short-term debt through February 7, 2022. 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, 2020, PGE had a $500 million revolving credit facility scheduled to expire in November 2023. The facility allows 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 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. The Company has elected to limit its borrowings under the revolving credit facility to cover any potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2020, PGE had no commercial paper outstanding.

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

Under the revolving credit facility, as of December 31, 2020, PGE had no borrowings or commercial paper outstanding, and no letters of credit issued. As a result, as of December 31, 2020, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities under which the Company has a total capacity of $220 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, letters of credit for a total of $60 million were outstanding, as of December 31, 2020.

On April 9, 2020, PGE obtained a 364-day term loan from lenders in the aggregate principal of $150 million. The term loan bears interest for the relevant interest period at LIBOR plus 1.25%. The interest rate is subject to adjustment pursuant to the terms of the loan. The credit agreement is classified as Notes Payable on the Company's Comparative Balance Sheet and expires on April 8, 2021, with any outstanding balance due and payable on such date.

During 2020, PGE issued a total of $430 million of First Mortgage Bond (FMBs).

On April 27, 2020, PGE issued $200 million of 3.15% Series FMBs due in 2030.

On December 10, 2020, the Company issued to certain institutional buyers in the private placement market $230 million aggregate principal amount of the Company's FMBs that consisted of:

- a series, due in 2027, in the amount of $160 million that will bear interest from its issuance date at an annual rate of 1.84%; and
- a series, due in 2032, in the amount of $70 million that will bear interest from its issuance date at an annual rate of 2.32%.

Pollution Control Revenue Bonds—On March 11, 2020, PGE completed the remarketing of an aggregate principal amount of $119 million of Pollution Control Revenue Refunding Bonds (PCRBs), which consist of $98 million aggregate principal of PCRBs that bear an interest rate of 2.125%, and $21 million aggregate principal of PCRBs that bear an interest rate of 2.375%, both due in 2033. At the time of remarketing, the Company chose a new interest rate period that was fixed term. The new interest rate was based on market conditions at the time of remarketing. The PCRBs are backed by the Company's Indenture of Mortgage by way of FMBs. Interest is payable semi-annually on the PCRBs.

As of December 31, 2020, total long-term debt outstanding was $3,059 million, of which $160 million is scheduled to mature in 2021.

PGE enters into financial agreements, and purchase and sale agreements involving physical delivery of, both power and natural gas 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, 2020, 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***

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 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 (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, including interest, which refunds 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 Circuit Court lifted the abatement on the class action proceedings and, heard oral argument on the Company's motion for Summary Judgment. In 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. The plaintiffs subsequently appealed the Circuit Court dismissal to the Court of Appeals for the State of Oregon.

In November 2019, the Court of Appeals issued an opinion that affirmed the Circuit Court dismissal. On December 30, 2019, the plaintiffs filed a motion for reconsideration, which the Court of Appeals denied on February 4, 2020.

On April 7, 2020, the plaintiffs filed a petition with the OSC requesting review and reversal of the Court of Appeals opinion. On July 16, 2020, the OSC issued an order that denied the petition for review.

***Deschutes River Alliance Clean Water Act Claims***

In August 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 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 March and April 2018, DRA and PGE filed cross-motions for summary judgment and PGE and the Confederated Tribes of Warm Springs (CTWS), which co-owns the Project, filed separate motions to dismiss. CTWS initially appeared as a friend of the court, but subsequently was found to be a necessary party to the lawsuit and joined as a defendant.

In August 2018, the U.S. District Court of the District of Oregon (District Court) 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 District Court 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.

In October 2018, DRA filed an appeal and PGE and CTWS filed cross-appeals to the Ninth Circuit Court of Appeals. The appeals are fully briefed and oral argument is set for May 7, 2021.

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

***Shareholder Lawsuits***

During September and October, 2020, three putative class action complaints were filed in U.S. District Court for the District of Oregon against PGE and certain of its officers, captioned *Hessel v. Portland General Electric Co.*, No. 20-cv-01523 (*"Hessel"*), *Cannataro v. Portland General Electric Co.*, No. 3:20-cv-01583 (*"Cannataro"*), and *Public Employees' Retirement System of Mississippi v. Portland General Electric Co.*, No. 20-cv-01786 (*"PERS of Mississippi"*). Two of these actions were filed on behalf of purported purchasers of PGE stock between April 24, 2020, and August 24, 2020; a third action was filed on behalf of purported purchasers of PGE stock between February 13, 2020, and August 24, 2020.

During the fourth quarter of 2020, the plaintiff in *Hessel* voluntarily dismissed his case and the court consolidated *Cannataro* and *PERS of Mississippi* into a single case captioned *In re Portland General Electric Company Securities Litigation* and appointed Public Employees' Retirement System of Mississippi lead plaintiff ("Lead Plaintiff"). On January 11, 2021, Lead Plaintiff filed an amended complaint asserting causes of action arising under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 for alleged misstatements and omissions regarding, among other things, PGE's alleged lack of sufficient internal controls and risks associated with PGE's trading activity in wholesale electric markets, purportedly on behalf of purchasers of PGE stock between February 13, 2020, and August 24, 2020. The complaint demands a jury trial and seeks compensatory damages of an unspecified amount and reimbursement of plaintiffs' costs, and attorneys' and expert fees.

The Company intends to vigorously defend against the lawsuit. Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

***Putative Shareholder Derivative Lawsuits***

On January 26, 2021, a putative shareholder derivative lawsuit, was filed in Multnomah County Circuit Court, Oregon, captioned *Shimberg v. Pope*, No. 21- cv-02957, against one current and one former PGE executive and several members of the Company's Board of Directors (collectively, the "Individual Defendants") and naming the Company as a nominal defendant only. The plaintiff asserts a claim for alleged breaches of fiduciary duties, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the Individual Defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks damages to be awarded to the Company of not less than $10 million, equitable relief to remedy the alleged breaches of fiduciary duty, and an award of plaintiff's attorneys' fees and costs.

Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

On March 17, 2021, a putative shareholder derivative lawsuit was filed in U.S. District Court for the District of Oregon, captioned *JS Halberstam Irrevocable Grantor Trust v. Davis*, No. 3:21-cv-00413-SI, against one current and one former PGE executive and all members of the Company's Board of Directors. The plaintiff asserts claims for alleged breaches of fiduciary duties, waste of corporate assets, contribution and indemnification, aiding and abetting, and gross mismanagement, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks equitable relief to remedy and prevent future alleged breaches of fiduciary duty, and an award of plaintiff's attorneys' fees and costs.

Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

On April 7, 2021, a putative shareholder derivative lawsuit was filed in Multnomah County Circuit Court, Oregon, captioned, *Ashabraner v. Pope*, 21-cv-13698, against one current and one former PGE executive and several members of the Company's Board of Directors. The plaintiff asserts a claim for alleged breaches of fiduciary duties, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks damages to be awarded to the Company, equitable relief, and an award of plaintiff's attorneys' fees and costs.

Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

10. None

11. (Reserved)

12. None

13. Changes in Officers and Directors:

    On October 28, 2020, the Board of Directors of the Company (the "Board") increased the size of the Board from twelve to fourteen directors and appointed Michael A. Lewis and James P. Torgerson to serve as directors of the Company, effective January 1, 2021. The Board appointed Mr. Lewis to serve on the Audit Committee and Finance Committee of the Board, and appointed Mr. Torgerson to serve on the Compensation and Human Resources Committee and Finance Committee of the Board, effective January 1, 2021.

    On October 29, 2020, the Company announced that James F. Lobdell, Senior Vice President, Finance, Chief Financial Officer and Treasurer, plans to retire from Portland General Electric Company, effective December 31, 2020. The Company also announced the appointment of James. A. Ajello as senior advisor, effective November 30, 2020, and as Senior Vice President, Finance, Chief Financial Officer and Treasurer, effective January 1, 2021.

Brett Sims was appointed Vice President, Strategy, Regulation, and Energy Supply on October 30, 2020.

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<br>(2) [ ] A Resubmission | / / | End of 2020/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 | 11,014,910,106 | 11,146,578,388 |
| 3 | Construction Work in Progress (107) | 200-201 | 430,009,860 | 329,538,575 |
| 4 | TOTAL Utility Plant (Enter Total of lines 2 and 3) | | 11,444,919,966 | 11,476,116,963 |
| 5 | (Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115) | 200-201 | 4,871,352,378 | 5,280,409,859 |
| 6 | Net Utility Plant (Enter Total of line 4 less 5) | | 6,573,567,588 | 6,195,707,104 |
| 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) | | 6,573,567,588 | 6,195,707,104 |
| 15 | Utility Plant Adjustments (116) | | 0 | 0 |
| 16 | Gas Stored Underground - Noncurrent (117) | | 0 | 0 |
| 17 | **OTHER PROPERTY AND INVESTMENTS** | | | |
| 18 | Nonutility Property (121) | | 5,782,688 | 5,734,880 |
| 19 | (Less) Accum. Prov. for Depr. and Amort. (122) | | 558,688 | 561,673 |
| 20 | Investments in Associated Companies (123) | | 0 | 0 |
| 21 | Investment in Subsidiary Companies (123.1) | 224-225 | 82,086,960 | 79,903,863 |
| 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) | | 92,280,433 | 88,696,635 |
| 29 | Special Funds (Non Major Only) (129) | | 0 | 0 |
| 30 | Long-Term Portion of Derivative Assets (175) | | 12,278,655 | 12,948,791 |
| 31 | Long-Term Portion of Derivative Assets – Hedges (176) | | 0 | 0 |
| 32 | TOTAL Other Property and Investments (Lines 18-21 and 23-31) | | 191,870,048 | 186,722,496 |
| 33 | **CURRENT AND ACCRUED ASSETS** | | | |
| 34 | Cash and Working Funds (Non-major Only) (130) | | 0 | 0 |
| 35 | Cash (131) | | 1,777,290 | 4,151,823 |
| 36 | Special Deposits (132-134) | | 7,985,779 | 16,360,268 |
| 37 | Working Fund (135) | | 5,000 | 5,000 |
| 38 | Temporary Cash Investments (136) | | 255,000,000 | 26,000,000 |
| 39 | Notes Receivable (141) | | 0 | 0 |
| 40 | Customer Accounts Receivable (142) | | 161,079,488 | 147,888,136 |
| 41 | Other Accounts Receivable (143) | | 27,683,325 | 23,110,998 |
| 42 | (Less) Accum. Prov. for Uncollectible Acct.-Credit (144) | | 15,642,244 | 4,476,885 |
| 43 | Notes Receivable from Associated Companies (145) | | 0 | 0 |
| 44 | Accounts Receivable from Assoc. Companies (146) | | 809,120 | 32,372 |
| 45 | Fuel Stock (151) | 227 | 17,886,804 | 34,191,533 |
| 46 | Fuel Stock Expenses Undistributed (152) | 227 | 0 | 0 |
| 47 | Residuals (Elec) and Extracted Products (153) | 227 | 0 | 0 |
| 48 | Plant Materials and Operating Supplies (154) | 227 | 46,230,120 | 51,952,091 |
| 49 | Merchandise (155) | 227 | 0 | 0 |
| 50 | Other Materials and Supplies (156) | 227 | 0 | 0 |
| 51 | Nuclear Materials Held for Sale (157) | 202-203/227 | 0 | 0 |
| 52 | Allowances (158.1 and 158.2) | 228-229 | 5,004,122 | 6,121,955 |

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

| Line No. | Title of Account (a) | Ref. Page No. (b) | Current Year End of Quarter/Year Balance (c) | Prior Year End Balance 12/31 (d) |
|---|---|---|---|---|
| 53 | (Less) Noncurrent Portion of Allowances | | 0 | 0 |
| 54 | Stores Expense Undistributed (163) | 227 | 2,688,473 | 3,657,581 |
| 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) | | 60,346,833 | 66,660,197 |
| 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) | | 97,058,139 | 86,440,635 |
| 62 | Miscellaneous Current and Accrued Assets (174) | | 0 | 0 |
| 63 | Derivative Instrument Assets (175) | | 45,105,863 | 37,582,745 |
| 64 | (Less) Long-Term Portion of Derivative Instrument Assets (175) | | 12,278,656 | 12,948,791 |
| 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) | | 700,739,456 | 486,729,658 |
| 68 | **DEFERRED DEBITS** | | | |
| 69 | Unamortized Debt Expenses (181) | | 12,381,227 | 10,192,104 |
| 70 | Extraordinary Property Losses (182.1) | 230a | 0 | 0 |
| 71 | Unrecovered Plant and Regulatory Study Costs (182.2) | 230b | 95,486,982 | 93,989,842 |
| 72 | Other Regulatory Assets (182.3) | 232 | 526,544,075 | 422,858,216 |
| 73 | Prelim. Survey and Investigation Charges (Electric) (183) | | 1,062,641 | 395,434 |
| 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) | | 24,216 | 34,840 |
| 77 | Temporary Facilities (185) | | 3 | 0 |
| 78 | Miscellaneous Deferred Debits (186) | 233 | 11,241,211 | 13,480,470 |
| 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) | | 20,518,419 | 21,808,511 |
| 82 | Accumulated Deferred Income Taxes (190) | 234 | 617,639,369 | 563,329,261 |
| 83 | Unrecovered Purchased Gas Costs (191) | | 0 | 0 |
| 84 | Total Deferred Debits (lines 69 through 83) | | 1,284,898,143 | 1,126,088,678 |
| 85 | TOTAL ASSETS (lines 14-16, 32, 67, and 84) | | 8,751,075,235 | 7,995,247,936 |

## 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 | 1,234,951,127 | 1,224,651,067 |
| 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 | 1,388,159,313 | 1,378,134,934 |
| 12 | Unappropriated Undistributed Subsidiary Earnings (216.1) | 118-119 | 4,547,299 | 2,364,202 |
| 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) | -11,105,713 | -9,615,910 |
| 16 | Total Proprietary Capital (lines 2 through 15) | | 2,612,277,331 | 2,591,259,598 |
| 17 | LONG-TERM DEBT | | | |
| 18 | Bonds (221) | 256-257 | 3,058,800,000 | 2,607,800,000 |
| 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 | 0 | 0 |
| 22 | Unamortized Premium on Long-Term Debt (225) | | 0 | 0 |
| 23 | (Less) Unamortized Discount on Long-Term Debt-Debit (226) | | 378,658 | 441,860 |
| 24 | Total Long-Term Debt (lines 18 through 23) | | 3,058,421,342 | 2,607,358,140 |
| 25 | OTHER NONCURRENT LIABILITIES | | | |
| 26 | Obligations Under Capital Leases - Noncurrent (227) | | 165,575,408 | 177,631,331 |
| 27 | Accumulated Provision for Property Insurance (228.1) | | 0 | 0 |
| 28 | Accumulated Provision for Injuries and Damages (228.2) | | 8,157,690 | 8,975,207 |
| 29 | Accumulated Provision for Pensions and Benefits (228.3) | | 410,077,224 | 358,925,128 |
| 30 | Accumulated Miscellaneous Operating Provisions (228.4) | | 0 | 0 |
| 31 | Accumulated Provision for Rate Refunds (229) | | 8,437,194 | 4,632,498 |
| 32 | Long-Term Portion of Derivative Instrument Liabilities | | 136,458,836 | 107,979,023 |
| 33 | Long-Term Portion of Derivative Instrument Liabilities - Hedges | | 0 | 0 |
| 34 | Asset Retirement Obligations (230) | | 291,070,650 | 279,375,319 |
| 35 | Total Other Noncurrent Liabilities (lines 26 through 34) | | 1,019,777,002 | 937,518,506 |
| 36 | CURRENT AND ACCRUED LIABILITIES | | | |
| 37 | Notes Payable (231) | | 150,000,000 | 0 |
| 38 | Accounts Payable (232) | | 294,098,090 | 292,625,385 |
| 39 | Notes Payable to Associated Companies (233) | | 0 | 0 |
| 40 | Accounts Payable to Associated Companies (234) | | 11,791,182 | 5,346,207 |
| 41 | Customer Deposits (235) | | 15,247,123 | 14,654,130 |
| 42 | Taxes Accrued (236) | 262-263 | 26,689,924 | 15,472,177 |
| 43 | Interest Accrued (237) | | 29,167,585 | 24,608,763 |
| 44 | Dividends Declared (238) | | 37,932,372 | 35,789,096 |
| 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) | | 15,729,568 | 17,441,259 |
| 48 | Miscellaneous Current and Accrued Liabilities (242) | | 11,999,595 | 40,413,388 |
| 49 | Obligations Under Capital Leases-Current (243) | | 24,192,962 | 24,869,839 |
| 50 | Derivative Instrument Liabilities (244) | | 150,934,109 | 131,143,945 |
| 51 | (Less) Long-Term Portion of Derivative Instrument Liabilities | | 136,458,837 | 107,979,023 |
| 52 | Derivative Instrument Liabilities - Hedges (245) | | 0 | 0 |
| 53 | (Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges | | 0 | 0 |
| 54 | Total Current and Accrued Liabilities (lines 37 through 53) | | 631,323,673 | 494,385,166 |
| 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 | 15,363,396 | 14,557,402 |
| 60 | Other Regulatory Liabilities (254) | 278 | 421,415,109 | 408,556,713 |
| 61 | Unamortized Gain on Reaquired Debt (257) | | 18,117 | 26,169 |
| 62 | Accum. Deferred Income Taxes-Accel. Amort.(281) | 272-277 | 0 | 0 |
| 63 | Accum. Deferred Income Taxes-Other Property (282) | | 819,161,947 | 800,256,070 |
| 64 | Accum. Deferred Income Taxes-Other (283) | | 173,317,318 | 141,330,172 |
| 65 | Total Deferred Credits (lines 56 through 64) | | 1,429,275,887 | 1,364,726,526 |
| 66 | TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65) | | 8,751,075,235 | 7,995,247,936 |

## 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<br>(a) | (Ref.) Page No.<br>(b) | Total Current Year to Date Balance for Quarter/Year<br>(c) | Total Prior Year to Date Balance for Quarter/Year<br>(d) | Current 3 Months Ended Quarterly Only No 4th Quarter<br>(e) | Prior 3 Months Ended Quarterly Only No 4th Quarter<br>(f) |
|---|---|---|---|---|---|---|
| 1 | UTILITY OPERATING INCOME | | | | | |
| 2 | Operating Revenues (400) | 300-301 | 2,157,212,368 | 2,147,982,409 | | |
| 3 | Operating Expenses | | | | | |
| 4 | Operation Expenses (401) | 320-323 | 1,174,454,586 | 1,109,201,823 | | |
| 5 | Maintenance Expenses (402) | 320-323 | 138,006,630 | 156,494,275 | | |
| 6 | Depreciation Expense (403) | 336-337 | 315,333,112 | 307,699,071 | | |
| 7 | Depreciation Expense for Asset Retirement Costs (403.1) | 336-337 | -3,966,273 | 6,887,698 | | |
| 8 | Amort. & Depl. of Utility Plant (404-405) | 336-337 | 64,345,245 | 64,406,427 | | |
| 9 | Amort. of Utility Plant Acq. Adj. (406) | 336-337 | | | | |
| 10 | Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407) | | 1,751,548 | -1,053,972 | | |
| 11 | Amort. of Conversion Expenses (407) | | | | | |
| 12 | Regulatory Debits (407.3) | | 40,375,546 | 18,618,061 | | |
| 13 | (Less) Regulatory Credits (407.4) | | 793,489 | 76,383 | | |
| 14 | Taxes Other Than Income Taxes (408.1) | 262-263 | 136,443,033 | 132,404,584 | | |
| 15 | Income Taxes - Federal (409.1) | 262-263 | 7,732,855 | 8,919,648 | | |
| 16 | - Other (409.1) | 262-263 | 17,587,387 | 11,992,123 | | |
| 17 | Provision for Deferred Income Taxes (410.1) | 234, 272-277 | 236,124,396 | 249,989,313 | | |
| 18 | (Less) Provision for Deferred Income Taxes-Cr. (411.1) | 234, 272-277 | 255,226,529 | 244,396,828 | | |
| 19 | Investment Tax Credit Adj. - Net (411.4) | 266 | | | | |
| 20 | (Less) Gains from Disp. of Utility Plant (411.6) | | 4,274 | | | |
| 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) | | 6,618,600 | 3,903,294 | | |
| 25 | TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24) | | 1,878,782,373 | 1,824,989,134 | | |
| 26 | Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27 | | 278,429,995 | 322,993,275 | | |

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 |
| 2,157,212,368 | 2,147,982,409 | | | | | 2 |
| | | | | | | 3 |
| 1,174,454,586 | 1,109,201,823 | | | | | 4 |
| 138,006,630 | 156,494,275 | | | | | 5 |
| 315,333,112 | 307,699,071 | | | | | 6 |
| -3,966,273 | 6,887,698 | | | | | 7 |
| 64,345,245 | 64,406,427 | | | | | 8 |
| | | | | | | 9 |
| 1,751,548 | -1,053,972 | | | | | 10 |
| | | | | | | 11 |
| 40,375,546 | 18,618,061 | | | | | 12 |
| 793,489 | 76,383 | | | | | 13 |
| 136,443,033 | 132,404,584 | | | | | 14 |
| 7,732,855 | 8,919,648 | | | | | 15 |
| 17,587,387 | 11,992,123 | | | | | 16 |
| 236,124,396 | 249,989,313 | | | | | 17 |
| 255,226,529 | 244,396,828 | | | | | 18 |
| | | | | | | 19 |
| 4,274 | | | | | | 20 |
| | | | | | | 21 |
| | | | | | | 22 |
| | | | | | | 23 |
| 6,618,600 | 3,903,294 | | | | | 24 |
| 1,878,782,373 | 1,824,989,134 | | | | | 25 |
| 278,429,995 | 322,993,275 | | | | | 26 |

STATEMENT OF INCOME FOR THE YEAR (continued)

| Line No. | Title of Account (a) | (Ref.) Page No. (b) | TOTAL Current Year (c) | TOTAL Previous Year (d) | Current 3 Months Ended Quarterly Only No 4th Quarter (e) | Prior 3 Months Ended Quarterly Only No 4th Quarter (f) |
|---|---|---|---|---|---|---|
| 27 | Net Utility Operating Income (Carried forward from page 114) | | 278,429,995 | 322,993,275 | | |
| 28 | Other Income and Deductions | | | | | |
| 29 | Other Income | | | | | |
| 30 | Nonutilty Operating Income | | | | | |
| 31 | Revenues From Merchandising, Jobbing and Contract Work (415) | | | | | |
| 32 | (Less) Costs and Exp. of Merchandising, Job. & Contract Work (416) | | | | | |
| 33 | Revenues From Nonutility Operations (417) | | 3,253,422 | 2,090,267 | | |
| 34 | (Less) Expenses of Nonutility Operations (417.1) | | 3,290,215 | 1,937,113 | | |
| 35 | Nonoperating Rental Income (418) | | 7,573 | -169,494 | | |
| 36 | Equity in Earnings of Subsidiary Companies (418.1) | 119 | 2,198,090 | 2,566,506 | | |
| 37 | Interest and Dividend Income (419) | | 519,241 | 1,091,115 | | |
| 38 | Allowance for Other Funds Used During Construction (419.1) | | 15,782,670 | 10,350,738 | | |
| 39 | Miscellaneous Nonoperating Income (421) | | -18,114,548 | 2,840,629 | | |
| 40 | Gain on Disposition of Property (421.1) | | | | | |
| 41 | TOTAL Other Income (Enter Total of lines 31 thru 40) | | 356,233 | 16,832,648 | | |
| 42 | Other Income Deductions | | | | | |
| 43 | Loss on Disposition of Property (421.2) | | | | | |
| 44 | Miscellaneous Amortization (425) | | | | | |
| 45 | Donations (426.1) | | 2,244,403 | 2,423,809 | | |
| 46 | Life Insurance (426.2) | | -4,267,563 | -2,625,511 | | |
| 47 | Penalties (426.3) | | 115,667 | 132,974 | | |
| 48 | Exp. for Certain Civic, Political & Related Activities (426.4) | | 1,219,135 | 1,199,586 | | |
| 49 | Other Deductions (426.5) | | 5,794,859 | 3,147,065 | | |
| 50 | TOTAL Other Income Deductions (Total of lines 43 thru 49) | | 5,106,501 | 4,277,923 | | |
| 51 | Taxes Applic. to Other Income and Deductions | | | | | |
| 52 | Taxes Other Than Income Taxes (408.2) | 262-263 | 204,195 | 103,956 | | |
| 53 | Income Taxes-Federal (409.2) | 262-263 | -2,034,288 | -1,209,756 | | |
| 54 | Income Taxes-Other (409.2) | 262-263 | -865,223 | -512,454 | | |
| 55 | Provision for Deferred Inc. Taxes (410.2) | 234, 272-277 | 1,616,606 | 2,116,948 | | |
| 56 | (Less) Provision for Deferred Income Taxes-Cr. (411.2) | 234, 272-277 | 5,773,681 | 788,473 | | |
| 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) | | -6,852,391 | -289,779 | | |
| 60 | Net Other Income and Deductions (Total of lines 41, 50, 59) | | 2,102,123 | 12,844,504 | | |
| 61 | Interest Charges | | | | | |
| 62 | Interest on Long-Term Debt (427) | | 123,508,651 | 118,738,532 | | |
| 63 | Amort. of Debt Disc. and Expense (428) | | 1,353,808 | 781,199 | | |
| 64 | Amortization of Loss on Reaquired Debt (428.1) | | 3,302,052 | 3,034,149 | | |
| 65 | (Less) Amort. of Premium on Debt-Credit (429) | | | | | |
| 66 | (Less) Amortization of Gain on Reaquired Debt-Credit (429.1) | | 8,052 | 8,052 | | |
| 67 | Interest on Debt to Assoc. Companies (430) | | | | | |
| 68 | Other Interest Expense (431) | | 5,727,993 | 4,692,335 | | |
| 69 | (Less) Allowance for Borrowed Funds Used During Construction-Cr. (432) | | 7,973,064 | 5,248,924 | | |
| 70 | Net Interest Charges (Total of lines 62 thru 69) | | 125,911,388 | 121,989,239 | | |
| 71 | Income Before Extraordinary Items (Total of lines 27, 60 and 70) | | 154,620,730 | 213,848,540 | | |
| 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) | | 154,620,730 | 213,848,540 | | |

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 | | 1,374,282,139 | 1,297,494,166 |
| 2 | Changes | | | |
| 3 | Adjustments to Retained Earnings (Account 439) | | | |
| 4 | Reclassification of stranded tax effects due to Tax Reform | | | 1,446,162 |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | TOTAL Credits to Retained Earnings (Acct. 439) | | | 1,446,162 |
| 10 | | | | |
| 11 | | | | |
| 12 | | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | TOTAL Debits to Retained Earnings (Acct. 439) | | | |
| 16 | Balance Transferred from Income (Account 433 less Account 418.1) | | 152,422,640 | 211,282,034 |
| 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 | -142,413,252 | ( 136,140,223) |
| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
| 35 | | | | |
| 36 | TOTAL Dividends Declared-Common Stock (Acct. 438) | | -142,413,252 | ( 136,140,223) |
| 37 | Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings | | 14,993 | 200,000 |
| 38 | Balance - End of Period (Total 1,9,15,16,22,29,36,37) | | 1,384,306,520 | 1,374,282,139 |
| | APPROPRIATED RETAINED EARNINGS (Account 215) | | | |
| 39 | | | | |
| 40 | | | | |

STATEMENT OF RETAINED EARNINGS

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

| Line No. | Item (a) | Contra Primary Account Affected (b) | Current Quarter/Year Year to Date Balance (c) | Previous Quarter/Year Year to Date Balance (d) |
|---|---|---|---|---|
| 41 | | | | |
| 42 | | | | |
| 43 | | | | |
| 44 | | | | |
| 45 | TOTAL Appropriated Retained Earnings (Account 215) | | | |
| | APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1) | | | |
| 46 | TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1) | | 3,852,793 | 3,852,795 |
| 47 | TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46) | | 3,852,793 | 3,852,795 |
| 48 | TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1) | | 1,388,159,313 | 1,378,134,934 |
| | UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account | | | |
| | Report only on an Annual Basis, no Quarterly | | | |
| 49 | Balance-Beginning of Year (Debit or Credit) | | 2,364,202 | ( 2,304) |
| 50 | Equity in Earnings for Year (Credit) (Account 418.1) | | 2,198,090 | 2,566,506 |
| 51 | (Less) Dividends Received (Debit) | | 14,993 | 200,000 |
| 52 | | | | |
| 53 | Balance-End of Year (Total lines 49 thru 52) | | 4,547,299 | 2,364,202 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>// | Year/Period of Report<br>End of 2020/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)<br>(a) | Current Year to Date Quarter/Year<br>(b) | Previous Year to Date Quarter/Year<br>(c) |
|---|---|---|---|
| 1 | Net Cash Flow from Operating Activities: | | |
| 2 | Net Income (Line 78(c) on page 117) | 154,620,730 | 213,848,540 |
| 3 | Noncash Charges (Credits) to Income: | | |
| 4 | Depreciation and Depletion | 375,712,084 | 378,993,196 |
| 5 | Amortization of Debt Discount | 4,647,808 | 3,807,296 |
| 6 | Amortization of Unrecovered Plant | 1,751,548 | -1,053,972 |
| 7 | Net Price Risk Management Activities | 12,267,046 | -42,043,425 |
| 8 | Deferred Income Taxes (Net) | -23,259,208 | 6,920,960 |
| 9 | Investment Tax Credit Adjustment (Net) | | |
| 10 | Net (Increase) Decrease in Receivables | -18,122,409 | 32,409,703 |
| 11 | Net (Increase) Decrease in Inventory | 24,113,641 | -12,239,920 |
| 12 | Net (Increase) Decrease in Allowances Inventory | | |
| 13 | Net Increase (Decrease) in Payables and Accrued Expenses | 24,612,708 | 1,612,200 |
| 14 | Net (Increase) Decrease in Other Regulatory Assets | -9,808,881 | 53,583,712 |
| 15 | Net Increase (Decrease) in Other Regulatory Liabilities | -17,330,796 | -19,571,074 |
| 16 | (Less) Allowance for Other Funds Used During Construction | 15,782,670 | 10,350,738 |
| 17 | (Less) Undistributed Earnings from Subsidiary Companies | 2,198,090 | 2,566,506 |
| 18 | Other: Margin and Customer Deposits | 8,967,482 | 2,045,734 |
| 19 | Other: Operating | 37,484,662 | -62,058,994 |
| 20 | | | |
| 21 | | | |
| 22 | Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21) | 557,675,655 | 543,336,712 |
| 23 | | | |
| 24 | Cash Flows from Investment Activities: | | |
| 25 | Construction and Acquisition of Plant (including land): | | |
| 26 | Gross Additions to Utility Plant (less nuclear fuel) | -795,174,628 | -614,595,774 |
| 27 | Gross Additions to Nuclear Fuel | | |
| 28 | Gross Additions to Common Utility Plant | | |
| 29 | Gross Additions to Nonutility Plant | -47,808 | -69,378 |
| 30 | (Less) Allowance for Other Funds Used During Construction | -15,782,670 | -10,350,738 |
| 31 | Other Capital Activities | -8,392,187 | -1,066,616 |
| 32 | | | |
| 33 | | | |
| 34 | Cash Outflows for Plant (Total of lines 26 thru 33) | -787,831,953 | -605,381,030 |
| 35 | | | |
| 36 | Acquisition of Other Noncurrent Assets (d) | | |
| 37 | Proceeds from Disposal of Noncurrent Assets (d) | | |
| 38 | Sale of Property | | 325,819 |
| 39 | Investments in and Advances to Assoc. and Subsidiary Companies | | |
| 40 | Contributions and Advances from Assoc. and Subsidiary Companies | 14,993 | 200,000 |
| 41 | Disposition of Investments in (and Advances to) | | |
| 42 | Associated and Subsidiary Companies | | |
| 43 | | | |
| 44 | Purchase of Investment Securities (a) | | |
| 45 | Proceeds from Sales of Investment Securities (a) | | |

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)<br>(a) | Current Year to Date Quarter/Year<br>(b) | Previous Year to Date Quarter/Year<br>(c) |
|---|---|---|---|
| 46 | Loans Made or Purchased | | |
| 47 | Collections on Loans | | |
| 48 | Other Investments | 451,607 | -5,173,341 |
| 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 | -5,749,505 | -8,488,330 |
| 54 | Sales of Trojan Decommissioning Securities | 8,773,036 | 13,113,169 |
| 55 | | | |
| 56 | Net Cash Provided by (Used in) Investing Activities | | |
| 57 | Total of lines 34 thru 55) | -784,341,822 | -605,403,713 |
| 58 | | | |
| 59 | Cash Flows from Financing Activities: | | |
| 60 | Proceeds from Issuance of: | | |
| 61 | Long-Term Debt (b) | 548,800,000 | 470,000,000 |
| 62 | Preferred Stock | | |
| 63 | Common Stock | -2,578,484 | -2,270,471 |
| 64 | Other (provide details in footnote): | | |
| 65 | | | |
| 66 | Net Increase in Short-Term Debt (c) | 150,000,000 | |
| 67 | Other (provide details in footnote): | | |
| 68 | | | |
| 69 | | | |
| 70 | Cash Provided by Outside Sources (Total 61 thru 69) | 696,221,516 | 467,729,529 |
| 71 | | | |
| 72 | Payments for Retirement of: | | |
| 73 | Long-term Debt (b) | -97,800,000 | -350,065,879 |
| 74 | Preferred Stock | | |
| 75 | Common Stock | | |
| 76 | Other (provide details in footnote): | -1,956,000 | -8,766,000 |
| 77 | Debt Issue Costs | -3,407,024 | -1,863,172 |
| 78 | Net Decrease in Short-Term Debt (c) | | |
| 79 | | | |
| 80 | Dividends on Preferred Stock | | |
| 81 | Dividends on Common Stock | -139,766,858 | -133,534,578 |
| 82 | Net Cash Provided by (Used in) Financing Activities | | |
| 83 | (Total of lines 70 thru 81) | 453,291,634 | -26,500,100 |
| 84 | | | |
| 85 | Net Increase (Decrease) in Cash and Cash Equivalents | | |
| 86 | (Total of lines 22,57 and 83) | 226,625,467 | -88,567,101 |
| 87 | | | |
| 88 | Cash and Cash Equivalents at Beginning of Period | 30,156,823 | 118,723,924 |
| 89 | | | |
| 90 | Cash and Cash Equivalents at End of period | 256,782,290 | 30,156,823 |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

***Schedule Page: 120 Line No.: 19 Column: b***

Amounts relate primarily to decrease in prepayments and settlements of asset retirement obligations.

***Schedule Page: 120 Line No.: 19 Column: c***

Amount primarily consists of $62 million of contributions to employee pension fund.

***Schedule Page: 120 Line No.: 76 Column: b***

Amount represents extinguishment costs of long term debt.

***Schedule Page: 120 Line No.: 76 Column: c***

Amount represents extinguishment costs of long term debt.

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.

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | / / | 2020/Q4 |

NOTES TO FINANCIAL STATEMENTS (Continued)

**Supplemental Disclosures**

**Supplemental Information to Statement of Cash Flows**

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

| | Balance at Beginning of Year | Balance at End of Year |
|---|---|---|
| Cash (131) | $ 4,151,823 | $ 1,777,290 |
| Working Funds (135) | 5,000 | 5,000 |
| Temporary Cash Investments (136) | 26,000,000 | 255,000,000 |
| | $ 30,156,823 | $ 256,782,290 |
| | | |
| | **2019** | **2020** |
| Cash paid during the year: | | |
| Interest | $ 120,967,642 | $ 120,814,283 |
| Allowance for borrowed funds used during construction | (5,248,924) | (7,973,064) |
| | $ 115,718,718 | $ 112,841,219 |
| | | |
| Income Taxes | $ 32,913,552 | $ 16,770,000 |
| Non-cash investing and financing activities: | | |
| Accrued capital additions | $ 76,125,230 | $ 72,417,164 |
| Accrued dividends payable | 35,789,096 | 37,932,372 |
| Assets obtained under leasing arrangements under ASC 842: | | |
| Finance leases | 153,811,914 | — |
| Operating leases | 56,460,807 | — |
| Preliminary engineering transferred to Construction work in progress | 1,667,673 | 28,433 |

## 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 four thousand square mile, state-approved service area is located entirely within the state of Oregon. PGE's allocated service area includes 51 incorporated cities. As of December 31, 2020, PGE served approximately 908 thousand retail customers with a service area population of approximately 1.9 million.

As of December 31, 2020, PGE had 3,639 members in its workforce (769 of which are contingent workers), with 721 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. The agreements cover 660 and 61 employees and expire March 2022 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, the non-service component of pension expense, operating leases, and implementation costs related to cloud computing arrangements.

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.

***Reclassifications***

To conform with current year presentation, the Company has reclassified Asset retirement obligation settlements of $9 million from Other, net in the operating activities section of the Statement of Cash Flows for the year ended December 31, 2019.

***Subsequent events***

PGE has evaluated the impact of events occurring after December 31, 2020 up to February 18, 2021, the date that the Company's U.S.

GAAP financial statements were issued, and has updated such evaluation for disclosure purposes through April 16, 2021. These financial statements include all necessary adjustments and disclosures resulting from such evaluations.

## NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### *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 $255 million as of December 31, 2020 and $26 million as of December 31, 2019 reflected in the Comparative Balance Sheet.

### *Customer 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 8 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. During 2020, the Company has taken steps to support customers during the COVID-19 pandemic, including suspending disconnections and late fees and developing time payment arrangements.

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 for credit losses are based on management's assessment of the current and forecasted probability of collection, aging of Customer Accounts Receivable, bad debt write-offs experience, actual customer billings, economic conditions, and other factors that help determine credit loss estimates for Customer Accounts Receivable.

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 Customer Accounts Receivable related to wholesale sales in 2020 or 2019.

### *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 when it is expected that the gain or loss upon settlement will be reflected in future retail rates. 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 variable power costs (NVPC).

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, while transactions that are not physically settled (financial transactions) are recorded on a net basis in Purchased Power upon financial settlement.

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral to 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 Current and Accrued

Assets in the Comparative Balance Sheet and were $8 million as of December 31, 2020 and $16 million as of December 31, 2019. Letters of credit provided as collateral are not recorded on the Company's Comparative Balance Sheet and were $12 million and $15 million as of December 31, 2020 and 2019, 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 inventories are 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 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. On June 30, 2020 the FERC issued a waiver that provides that, for the 12-month period starting March 2020, jurisdictional utilities may apply an alternative AFDC calculation formula that excludes the actual outstanding short-term debt balance and replaces it with the simple average of the actual 2019 short-term debt balance. The purpose of the waiver is to allow relief from the detrimental impacts of issuing short-term debt on the allowance for equity funds used during construction in response to COVID-19. PGE adopted the waiver in the second quarter of 2020. AFDC is capitalized as part of the cost of plant and credited to the Statement of Income. The average rate used by PGE was 6.9% in 2020 and 7.1% in 2019. AFDC from borrowed funds, reflected as a reduction to Interest Charges, was $8 million in 2020 and $5 million in 2019. AFDC from equity funds, included in Other Income, was $16 million in 2020 and $10 million in 2019.

*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 3.5% in 2020 and 3.6% in 2019. 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. In 2016 PGE completed a depreciation study based on 2015 data, 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 2061. 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 | 97 |
| Wind | 31 |
| Transmission | 58 |
| Distribution | 46 |
| General | 13 |

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 Provision for Depreciation, Amortization, and Depletion.

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 $388 million and $366 million as of December 31, 2020 and 2019, respectively, with amortization expense of $64 million in both 2020 and 2019. Future estimated amortization expense as of December 31, 2020 is as follows: $57 million in 2021; $51 million in 2022; $42 million in 2023; $37 million in 2024; and $25 million in 2025.

***Marketable Securities***

*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 decommissioned 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 investments held therein.

All of PGE's investments in marketable securities included in NDT and NQBP 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 NQBP trust assets are included in Other Income. Realized and unrealized gains and losses on the NDT fund assets are recorded as regulatory liabilities or assets, respectively, for future ratemaking treatment. The cost of securities sold in the NDT is based on the average cost method whereas cost of securities sold in the NQBP is based on the first in first out 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, future customer prices can be adjusted to reflect a portion of the difference between: i) NVPC forecast each year and included in customer prices (baseline NVPC); and ii) actual NVPC for the year. 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 2020 and 2019.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Operating Revenues, net in PGE's Statement of Income, while any estimated collection from customers is recorded as a reduction in Purchased Power. For the year ended December 31, 2020, PGE's actual NVPC was $114 million above baseline NVPC. PGE excluded from actual NVPC and will not be pursuing regulatory recovery for amounts related to trading positions that resulted in realized losses of $127 million during the third quarter of 2020. These losses were the result of a convergence of increased wholesale electricity prices at various market hubs due to extreme weather conditions, constraints to regional transmission facilities and changes in power supply in the West that occurred in August 2020. The Company no longer has net market exposure from these trading positions. After adjusting for the realized losses on the trading positions, PGE's actual NVPC for 2020 was $13 million below baseline NVPC, which is within the established deadband range resulting in no estimated refund to customers.

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. The present value of estimated future decommissioning costs is capitalized and included in Net Utility Plant on the Comparative Balance Sheet with a corresponding offset to ARO. For revisions to AROs in which the related asset is no longer in service, the corresponding offset is recorded as a Regulatory asset on the Comparative Balance Sheet, except for those AROs related to non-utility assets which is charged to Miscellaneous Nonoperating Income (Acct 421) on the Statement of Income. Such estimates are revised periodically, with actual settlements charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, with such depreciation 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 Accretion Expense for Asset (Acct 411) 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, 2020, PGE had a net regulatory liability related to Utility plant AROs in the amount of $37 million and a net regulatory asset related to Trojan decommissioning ARO activities of $88 million. As of December 31, 2019, PGE had a net regulatory liability related to Utility plant AROs in the amount of $54 million and a net regulatory asset related to Trojan decommissioning ARO activities of $91 million. For additional information concerning the Company's regulatory assets and liabilities 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 why the estimate cannot be made.

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

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

For additional information concerning the Company's contingencies, see Note 17, Contingencies.

***Accumulated Other Comprehensive Loss***

Accumulated other Comprehensive Loss (AOCL) presented on the Comparative Balance Sheet is comprised of the difference between the obligations of the non-qualified benefit plans recognized in net income and the unfunded position.

***Revenue Recognition***

Operating Revenues are 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 Operating 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 services provided, are regulated by the OPUC or the 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, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $46 million in 2020 and $45 million in 2019.

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 remained unbilled to customers. The unbilled revenues estimate, which is classified as Accrued Utility 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 Operating Revenue to be billed to customers in future periods or defers the recognition of certain Operating 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.

***Recently Adopted Accounting Pronouncements***

On January 1, 2020, PGE adopted 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 disclosures. As the standard relates only to disclosures, the implementation did not result in an impact to the results of operation, financial position or cash flows.

On January 1, 2020, PGE adopted 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.* ASU 2018-15 provides guidance on implementation costs incurred in a cloud computing arrangement that is a service contract and aligns the accounting for such costs with the guidance on capitalizing costs associated with developing or obtaining internal-use software. For FERC reporting purposes, PGE plans to continue to capitalize such implementation costs to Utility Plant for material projects. PGE applied the amendments of this ASU prospectively, and the implementation did not have a material impact on PGE's results of operation, financial position or cash flows.

On January 1, 2020, PGE adopted ASU 2016-13 *Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments.* ASU 2016-13 replaces the incurred loss impairment methodology in previous GAAP with a methodology that reflects expected credit losses, and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. PGE applied this ASU using a modified-retrospective approach, and as a result, amounts recorded prior to January 1, 2020 have not been retrospectively restated. Under the new standard, PGE estimates current expected credit losses for retail sales based on an assessment of the current and forecasted probability of collection, aging of Customer Accounts Receivable, bad debt write-offs experience, actual customer billings, economic conditions, and other significant events that may impact the collectability of Customer Accounts Receivable and unbilled revenues. Provisions for current expected credit losses related to retail sales, and changes to the amount of expected credit losses for existing receivables, 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. The implementation did not have a material impact on PGE's results of operation, financial position, or cash flows.

On April 1, 2020, PGE adopted ASU 2020-04 *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting.* ASU 2020-04 provides optional guidance for a limited period of time to ease the potential burden in accounting for (or recognizing the effects of) reference rate reform on financial reporting. PGE applied the amendments of this ASU prospectively, and the implementation did not have a material impact on PGE's results of operation, financial position, or cash flows.

PGE has adopted 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. As the standard relates only to disclosures, the adoption did not have a material impact on PGE's results of operation, financial position, or cash flows.

## NOTE 3: COMPARATIVE BALANCE SHEET COMPONENTS

*Accumulated Provision for Uncollectible Accounts*

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

| | Years Ended December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Balance as of beginning of year | $ 4 | $ 15 |
| Increase in provision * | 15 | 2 |
| Amounts written off, less recoveries | (3) | (13) |
| Balance as of end of year | $ 16 | $ 4 |

* As of December 31, 2020, PGE has deferred as a regulatory asset $8 million in bad debt expense pursuant to the OPUC's COVID-19 deferral order.

***Net Utility Plant***

Net Utility Plant, consist of the following (in millions):

| | As of December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Utility Plant: | | |

| | | |
|---|---|---|
| Generation | $ 4,466 | $ 4,954 |
| Transmission | 967 | 849 |
| Distribution | 4,137 | 3,917 |
| General | 683 | 661 |
| Intangible | 753 | 758 |
| Total in service | 11,006 | 11,139 |
| Less: Accumulated Provision for Depreciation, Amortization, and Depletion | (4,871) | (5,280) |
| Total in service, net | 6,135 | 5,859 |
| Held for future use | 9 | 7 |
| Construction Work In Progress | 430 | 330 |
| Net Utility Plant | $ 6,574 | $ 6,196 |

## 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, 2020 and 2019. 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 that 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, 2020 and 2019, 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, 2020 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Other(2) | Total |
| Assets: | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Temporary Cash Investments | $ 255 | $ — | $ — | $ — | $ 255 |
| Nuclear decommissioning trust: (1) | | | | | |
| Debt securities: | | | | | |
| Domestic government | 9 | 11 | — | — | 20 |
| Corporate credit | — | 13 | — | — | 13 |
| Money market funds measured at NAV (2) | — | — | — | 12 | 12 |
| 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 | — | 4 | 4 | — | 8 |
| Natural gas | — | 36 | 1 | — | 37 |
| | $ 273 | $ 64 | $ 5 | $ 12 | $ 354 |
| Liabilities: | | | | | |
| Price risk management activities: (1) (4) | | | | | |
| Electricity | $ — | $ 5 | $ 141 | $ — | $ 146 |
| Natural gas | — | 4 | 1 | — | 5 |
| | $ — | $ 9 | $ 142 | $ — | $ 151 |

(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 $33 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, 2019 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Other(2) | Total |
| Assets: | | | | | |
| Temporary Cash Investments | $ 26 | $ — | $ — | $ — | $ 26 |
| Nuclear decommissioning trust: (1) | | | | | |
| Debt securities: | | | | | |
| Domestic government | 8 | 16 | — | — | 24 |

| | | | | | |
|---|---|---|---|---|---|
| Corporate credit | — | 9 | — | — | 9 |
| Money market funds measured at NAV (2) | — | — | — | 13 | 13 |
| 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 | — | 9 | 7 | — | 16 |
| Natural gas | — | 21 | 1 | — | 22 |
| | $ 43 | $ 55 | $ 8 | $ 13 | $ 119 |
| Liabilities: | | | | | |
| Price risk management activities: (1) (4) | | | | | |
| Electricity | $ — | $ 14 | $ 105 | $ — | $ 119 |
| Natural gas | — | 12 | — | — | 12 |
| | $ — | $ 26 | $ 105 | $ — | $ 131 |

(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 $29 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 securities held by the funds do not exceed 90 days and investors have the ability to redeem shares daily at the net asset value of the respective fund. 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 the National Association of Securities Dealers Automated Quotations (NASDAQ) and the New York Stock Exchange (NYSE).

***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 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.

***Assets and liabilities from price risk management activities,*** recorded at fair value in PGE's Comparative Balance Sheet, consist of derivative instruments entered into by the Company to manage its risk exposure to commodity price and foreign currency exchange rates and reduce volatility in NVPC. 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, 2020:** | | | | | | | |
| Electricity physical forwards | $ — | $ 141 | Discounted cash flow | Electricity forward price (per MWh) | $ 11.17 | $ 51.18 | $ 29.74 |
| Natural gas financial swaps | 1 | 1 | Discounted cash flow | Natural gas forward price (per Dth) | 1.52 | 4.33 | 2.29 |
| Electricity financial futures | 4 | — | Discounted cash flow | Electricity forward price (per MWh) | 8.78 | 58.42 | 43.71 |
| | $ 5 | $ 142 | | | | | |
| **As of December 31, 2019:** | | | | | | | |
| Electricity physical forwards | $ — | $ 104 | Discounted cash flow | Electricity forward price (per MWh) | $ 12.53 | $ 59.00 | $ 36.92 |
| Natural gas financial swaps | 1 | — | Discounted cash flow | Natural gas forward price (per Dth) | 1.39 | 3.73 | 1.90 |
| Electricity financial futures | 7 | 1 | Discounted cash flow | Electricity forward price (per MWh) | 10.57 | 66.32 | 45.11 |
| | $ 8 | $ 105 | | | | | |

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, | |
|---|---|---|
| | 2020 | 2019 |
| Net liabilities from price risk management activities as of beginning of year | $ 97 | $ 88 |
| Net realized and unrealized losses/(gains) * | 38 | 10 |
| Net transfers from Level 3 to Level 2 | 2 | (1) |
| Net liabilities from price risk management activities as of end of year | $ 137 | $ 97 |
| Level 3 net unrealized losses/(gains) that have been fully offset by the effect of regulatory accounting | $ 47 | $ 16 |

* Includes $9 million in net realized gains in 2020 and $6 million in 2019.

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, 2020 and 2019, 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 into and from 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 FMBs and Pollution Control Revenue Bonds (PCRBs) is classified as a Level 2 fair value measurement.

As of December 31, 2020, the carrying amount of PGE's long-term debt was $3,059 million and its estimated aggregate fair value was $3,808 million. As of December 31, 2019, the carrying amount of PGE's long-term debt was $2,608 million with an estimated aggregate fair value of $3,039 million.

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 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 the Company's long-term wholesale contracts. Wholesale market transactions include purchases and sales of both power and fuel resulting from economic dispatch decisions with respect to 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 flows.

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign exchange rate risk in order to reduce volatility in NVPC for its retail customers. Such derivative instruments, recorded at fair value on the Comparative Balance Sheet, may include forward, future, 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 intend to 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, | |
|---|---|---|
| | 2020 | 2019 |
| **Current assets:** | | |
| Commodity contracts: | | |
| Electricity | $ 4 | $ 9 |
| Natural gas | 29 | 16 |
| Total current derivative assets(1) | 33 | 25 |
| **Noncurrent assets:** | | |
| Commodity contracts: | | |
| Electricity | 4 | 7 |
| Natural gas | 8 | 6 |
| Total noncurrent derivative assets | 12 | 13 |
| Total derivative assets | $ 45 | $ 38 |
| **Current liabilities:** | | |
| Commodity contracts: | | |
| Electricity | $ 13 | $ 14 |
| Natural gas | 2 | 9 |
| Total current derivative liabilities | 15 | 23 |
| **Noncurrent liabilities:** | | |
| Commodity contracts: | | |
| Electricity | 133 | 105 |
| Natural gas | 3 | 3 |
| Total noncurrent derivative liabilities | 136 | 108 |
| Total derivative liabilities(2) | $ 151 | $ 131 |

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, | | | | | |
|---|---|---|---|---|---|---|
| | 2020 | | | 2019 | | |
| Commodity contracts: | | | | | | |
| Electricity | | 6 | MWh | | 6 | MWh |
| Natural gas | | 137 | Dth | | 145 | Dth |
| Foreign currency contracts | $ | 19 | Canadian | $ | 23 | Canadian |

PGE has elected to report positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement at gross values on the Comparative Balance Sheet. 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, 2020, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $2 million, for which PGE has posted no collateral. Of the gross amounts recognized as of December 31, 2020, $1 million was for electricity and $1 million was for natural gas. As of December 31, 2019, PGE had no material gross master netting arrangements.

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, | | | |
|---|---|---|---|---|
| | 2020 | | 2019 | |
| Commodity contracts: | | | | |
| Electricity | $ | 160 | $ | 20 |
| Natural Gas | | (34) | | (32) |
| Foreign currency contracts | | (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 losses of $12 million and net gains of $2 million for the years ended December 31, 2020 and 2019, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table presents the years in which the net unrealized (gains)/losses recorded as of December 31, 2020 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

| | 2021 | | 2022 | | 2023 | | 2024 | | 2025 | | Thereafter | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Commodity contracts: | | | | | | | | | | | | | | |
| Electricity | $ | 9 | $ | 4 | $ | 8 | $ | 8 | $ | 9 | $ | 100 | $ | 138 |
| Natural gas | | (27) | | (5) | | — | | — | | — | | — | | (32) |
| Net unrealized (gain)/loss | $ | (18) | $ | (1) | $ | 8 | $ | 8 | $ | 9 | $ | 100 | $ | 106 |

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 derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2020 was $148 million, for which the Company has posted $13 million in collateral, consisting of $12 million of letters of credit and $1 million of cash. If the credit-risk-related contingent features underlying these agreements were triggered as of December 31, 2020, the cash requirement to either post as collateral or settle the instruments immediately would have been $142 million. As of December 31, 2020, PGE had $6 million 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, | |
|---|---|---|
| | **2020** | **2019** |
| **Assets from price risk management activities:** | | |
| Counterparty A | 12 % | 35 % |
| Counterparty B | 17 | 13 |
| Counterparty C | 21 | 11 |
| Counterparty D | 16 | 11 |
| | 66 % | 70 % |
| **Liabilities from price risk management activities:** | | |
| Counterparty E | 93 % | 79 % |

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

## NOTE 6: REGULATORY ASSETS AND LIABILITIES

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

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

| | Remaining Amortization Period | As of December 31, | |
|---|---|---|---|
| | | **2020** | **2019** |
| Regulatory assets: | | | |
| Price risk management | 2035 | $ 124 | $ 95 |
| Pension plan | (1) | 240 | 213 |
| Deferred income taxes | (3) | $ 56 | 45 |

| | | | |
|---|---|---|---|
| Other | Various | 107 | 70 |
| Total regulatory assets | | $ 527 | $ 423 |
| Regulatory liabilities: | | | |
| Deferred income taxes | (3) | 295 | 304 |
| Asset retirement obligations | (2) | 37 | 54 |
| Price risk management | 2021 | 18 | 1 |
| Other | Various | 71 | 50 |
| Total regulatory liabilities | | $ 421 | $ 409 |

(1) Recovery expected over the average service life of employees.
(2) Recovery or refund expected over the estimated lives of the underlying assets and treated as a reduction to rate base.
(3) Refund expected primarily through amortization 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 will be refunded to customers when the temporary differences reverse. 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 over the book life of the related assets. The Company uses the average rate assumption method to account for the refund to customers. For further information, see Note 11, Income Taxes.

*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 Expense 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, | |
|---|---|---|
| | 2020 | 2019 |
| Trojan decommissioning activities | $ 139 | $ 137 |
| Utility plant | 118 | 126 |
| Non-utility property | 34 | 16 |
| Total asset retirement obligations | $ 291 | $ 279 |

*Trojan decommissioning activities* represents the present value of future decommissioning costs for PGE's 67.5% ownership interest in Trojan, 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 will store 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 2059. The Company recorded accretion of $6 million and a reduction of $4 million due to settled liabilities.

Under a settlement agreement reached with the USDOE, the Company receives annual reimbursement from the USDOE for certain costs related to monitoring the ISFSI. Pursuant to this process, the USDOE reimbursed the co-owners $5 million in 2020 for costs incurred in 2019 and $4 million in 2019 for costs incurred in 2018 resulting from USDOE delays in accepting spent nuclear fuel.

*Utility Plant* represents AROs that have been recognized for the Company's thermal and wind generation sites, and distribution and transmission assets, the disposal of which is governed by environmental regulation. During 2020, the Company recorded an overall decrease in utility AROs of $8 million, with the change comprised of new liabilities incurred of $5 million, reduction of $4 million due to revisions in estimated cash flows, accretion of $4 million, and a reduction of $13 million due to settled liabilities.

*Non-utility property* primarily represents AROs that have been recognized for portions of unregulated properties that are currently or previously leased to third parties. Revisions to estimates for non-utility AROs relate to assets that are no longer in service and the offset is charged directly to Miscellaneous Nonoperationg Income (Acct 421) on the Statement of Income in the period in which the revisions are probable and reasonably estimate. Non-utility AROs are not subject to regulatory deferral.

In 2020, PGE performed a decommissioning study to update its ARO liability which resulted in a $21 million increase to non-utility property AROs. As part of this study, the Company also established an ARO liability of $3 million related to utility properties and was charged to expense in the Statement of Income. PGE plans to pursue regulatory recovery for the utility portion of the ARO update, however as of December 31, 2020 no amounts have been deferred as a regulatory asset.

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

| | Years Ended December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Balance as of beginning of year | $ 279 | $ 197 |
| Liabilities incurred | 3 | — |
| Liabilities settled | (18) | (9) |
| Accretion expense | 10 | 9 |
| Revisions in estimated cash flows | 17 | 82 |
| Balance as of end of year | $ 291 | $ 279 |

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 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.

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. Removal costs are charged to accumulated asset retirement removal costs, which is included in Regulatory liabilities on PGE's Comparative Balance Sheet.

## NOTE 8: CREDIT FACILITIES

As of December 31, 2020, PGE had a $500 million revolving credit facility scheduled to expire in November 2023. The Company has the ability to expand the revolving credit facility to $600 million, if needed. The credit facility allows 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, including 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, 2020, PGE was in compliance with this covenant with a 56.4% debt to total capital ratio.

PGE typically classifies 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, 2020, PGE had no borrowings outstanding and there were no commercial paper or letters of credit issued. As a result, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days. The Company has elected to limit its borrowings under the revolving credit facility to cover any potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2020, PGE had no commercial paper outstanding.

In addition, PGE has four letter of credit facilities that provide a total capacity 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, a total of $60 million of letters of credit were outstanding as of December 31, 2020. Outstanding letters of credit are not reflected on the Company's Comparative Balance Sheet.

On April 9, 2020, PGE obtained a 364-day unsecured term loan from lenders in the aggregate principal of $150 million. The term loan bears interest for the relevant interest period at LIBOR plus 1.25%. The interest rate is subject to adjustment pursuant to the terms of the loan. The credit agreement is classified as Notes Payable on the Company's Comparative Balance Sheet and expires on April 8, 2021, with any outstanding balance due and payable on such date.

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, 2022.

Short-term borrowings under these credit facilities, and related interest rates, are reflected in the following table (dollars in millions).

| | Year Ended December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Average daily amount of short-term debt outstanding | $ 131 | $ 7 |
| Weighted daily average interest rate * | 1.5 % | 2.6 % |
| Maximum amount outstanding during the year | $ 225 | $ 46 |

* Excludes the effect of commitment fees, facility fees and other financing fees.

## NOTE 9: LONG-TERM DEBT

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

| | As of December 31, | | | |
|---|---|---|---|---|
| | 2020 | | 2019 | |
| **First Mortgage Bonds**, rates range from 1.84% to 9.31%, with a weighted average rate of 4.14% in 2020 and 4.63% in 2019, due at various dates through 2050 | $ | 2,940 | $ | 2,510 |
| **Pollution Control Revenue Bonds**, rates at 2.13% and 2.38%, due 2033 | | 119 | | 119 |
| Pollution Control Revenue Bonds held by PGE | | — | | (21) |
| **Total long-term debt** | $ | 3,059 | $ | 2,608 |

*First Mortgage Bonds*—On April 27, 2020, PGE issued $200 million of 3.15% Series FMBs due in 2030.

On December 10, 2020, PGE issued $230 million aggregate principal amount of the Company's FMBs that consisted of:

1 a series, due in 2027, in the amount of $160 million that will bear interest from its issuance date at an annual rate of 1.84%; and

2 a series, due in 2032, in the amount of $70 million that will bear interest from its issuance date at an annual rate of 2.32%.

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*—On March 11, 2020, PGE completed the remarketing of an aggregate principal amount of $119 million of Pollution Control Revenue Refunding Bonds (PCRBs), which consist of $98 million aggregate principal of PCRBs that bear an interest rate of 2.125%, and $21 million aggregate principal of PCRBs that bear an interest rate of 2.375%, both due in 2033. At the time of remarketing, the Company chose a new interest rate period that was fixed term. The new interest rate was based on market conditions at the time of remarketing. The PCRBs could be backed by FMBs or a bank letter of credit depending on market conditions. Interest is payable semi-annually on the PCRBs.

As of December 31, 2020, the future minimum principal payments on long-term debt are as follows (in millions):

**Years ending December 31:**

| | | |
|---|---|---|
| 2021 | $ | 160 |
| 2022 | | — |
| 2023 | | — |
| 2024 | | 80 |
| 2025 | | — |
| Thereafter | | 2,819 |
| | $ | 3,059 |

## NOTE 10: EMPLOYEE BENEFITS

***Pension and Other Postretirement Plans***

*Defined Benefit Pension Plan*—PGE sponsors a non-contributory defined benefit pension plan, which is 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.

As expected, PGE contributed no additional funds to the pension plan in 2020 after contributing $62 million in 2019. PGE does not expect to contribute to the pension plan in 2021.

*Other Postretirement Benefits*—PGE offers non-contributory postretirement health and life insurance plans, and provides health reimbursement arrangements (HRAs) to its employees (collectively, “Other Postretirement Benefits” in the following tables). PGE’s obligation pursuant to the postretirement health plan is limited by establishing a maximum benefit per employee with any additional cost the responsibility of the employee.

The assets of these plans are held in voluntary employees’ beneficiary association trusts and are comprised of money market funds, equity securities, 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, bonds, 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. For further information regarding these trust investments, see Note 4, Fair Value of Financial Instruments.

*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. 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):

| | 2020 | | | 2019 | | |
|---|---|---|---|---|---|---|
| | NQBP | Other NQBP | Total | NQBP | Other NQBP | Total |
| Non-qualified benefit plan trust | $ 19 | $ 23 | $ 42 | $ 17 | $ 21 | $ 38 |
| Non-qualified benefit plan liabilities | 28 | 75 | 103 | 26 | 79 | 105 |

*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 the implementation of the asset allocation and oversight of the benefit plan investments. The Company’s investment strategy 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, | | | |
|---|---|---|---|---|
| | 2020 | | 2019 | |
| | Actual | Target * | Actual | Target * |

| | | | | |
|---|---|---|---|---|
| **Defined Benefit Pension Plan:** | | | | |
| Equity securities | 67 % | 65 % | 64 % | 65 % |
| Debt securities | 33 | 35 | 36 | 35 |
| Total | 100 % | 100 % | 100 % | 100 % |
| **Other Postretirement Benefit Plans:** | | | | |
| Equity securities | 60 % | 57 % | 61 % | 59 % |
| Debt securities | 40 | 43 | 39 | 41 |
| Total | 100 % | 100 % | 100 % | 100 % |
| **Non-Qualified Benefits Plans:** | | | | |
| Equity securities | 17 % | 12 % | 17 % | 12 % |
| Debt securities | 6 | 11 | 7 | 12 |
| Insurance contracts | 77 | 77 | 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.

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, 2020:** | | | | | |
| **Defined Benefit Pension Plan assets:** | | | | | |
| Equity securities—Domestic | $ 49 | $ — | $ — | $ — | $ 49 |
| Investments measured at NAV: | | | | | |
| Money market funds | — | — | — | 6 | 6 |
| Collective trust funds | — | — | — | 692 | 692 |
| Private equity funds | — | — | — | 6 | 6 |
| | $ 49 | $ — | $ — | $ 704 | $ 753 |
| **Other Postretirement Benefit Plans assets:** | | | | | |
| Money market funds | $ 4 | $ — | $ — | $ — | $ 4 |

| | | | | | |
|---|---|---|---|---|---|
| Equity securities: | | | | | |
| Domestic | — | 3 | — | — | 3 |
| International | 9 | — | — | — | 9 |
| Debt securities—Domestic | — | 5 | — | — | 5 |
| Investments measured at NAV: | | | | | |
| Money market funds | — | — | — | 5 | 5 |
| Collective trust funds | — | — | — | 9 | 9 |
| | $ 13 | $ 8 | $ — | $ 14 | $ 35 |
| **As of December 31, 2019:** | | | | | |
| **Defined Benefit Pension Plan assets:** | | | | | |
| Equity securities—Domestic | $ 49 | $ — | $ — | $ — | $ 49 |
| Investments measured at NAV: | | | | | |
| Money market funds | — | — | — | 5 | 5 |
| Collective trust funds | — | — | — | 632 | 632 |
| Private equity funds | — | — | — | 9 | 9 |
| | $ 49 | $ — | $ — | $ 646 | $ 695 |
| **Other Postretirement Benefit Plans assets:** | | | | | |
| Money market funds | $ 4 | $ — | $ — | $ — | $ 4 |
| Equity securities: | | | | | |
| Domestic | — | 3 | — | — | 3 |
| International | 9 | — | — | — | 9 |
| Debt securities—Domestic government | — | 5 | — | — | 5 |
| Investments measured at NAV: | | | | | |
| Money market funds | — | — | — | 5 | 5 |
| Collective trust funds | — | — | — | 8 | 8 |
| | $ 13 | $ 8 | $ — | $ 13 | $ 34 |

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

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 NAV. 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.

*Debt Securities*—Debt security investment funds are classified as Level 2 securities as pricing for underlying securities are determined by evaluating pricing data, such as broker quotes for similar securities, adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, if applicable.

*Collective trust funds*—Domestic and international mutual fund assets and debt security assets, including municipal debt and corporate credit securities, mortgage-backed securities, and asset back securities assets, are included in commingled trusts or separately managed accounts. The Company believes the redemption value of the collective trust funds are likely to be the fair value, which is represent by the net asset value as a practical expedient. The funds are valued at NAV as a practical expedient and are not classified 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 and are not classified in the fair value hierarchy.

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, 2020 and 2019. 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 | |
|---|---|---|---|---|---|---|
| | 2020 | 2019 | 2020 | 2019 | 2020 | 2019 |
| **Benefit obligation:** | | | | | | |
| As of January 1 | $ 905 | $ 811 | $ 71 | $ 72 | $ 26 | $ 24 |
| Service cost | 17 | 16 | 2 | 2 | — | — |
| Interest cost | 31 | 34 | 2 | 3 | 1 | 1 |
| Participants' contributions | — | — | — | 2 | — | — |
| Actuarial loss (gain) | 104 | 88 | 4 | 8 | 3 | 3 |
| Benefit payments | (44) | (42) | (4) | (6) | (2) | (2) |
| Administrative expenses | (3) | (2) | — | — | — | — |
| Plan amendment | — | — | 1 | (9) | — | — |
| Curtailment gain | — | — | — | (1) | — | — |
| As of December 31 | $ 1,010 | $ 905 | $ 76 | $ 71 | $ 28 | $ 26 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Fair value of plan assets:** | | | | | | | | | | | | |
| As of January 1 | $ | 695 | $ | 546 | $ | 34 | $ | 30 | $ | 17 | $ | 16 |
| Actual return on plan assets | | 105 | | 131 | | 2 | | 5 | | 1 | | 1 |
| Company contributions | | — | | 62 | | 3 | | 3 | | 3 | | 2 |
| Participants' contributions | | — | | — | | — | | 2 | | — | | — |
| Benefit payments | | (44) | | (42) | | (4) | | (6) | | (2) | | (2) |
| Administrative expenses | | (3) | | (2) | | — | | — | | — | | — |
| As of December 31 | $ | 753 | $ | 695 | $ | 35 | $ | 34 | $ | 19 | $ | 17 |
| **Unfunded position as of December 31** | $ | (257) | $ | (210) | $ | (41) | $ | (37) | $ | (9) | $ | (9) |
| **Accumulated benefit plan obligation as of December 31** | $ | 907 | $ | 813 | | N/A | | N/A | $ | 24 | $ | 26 |
| **Classification in Comparative Balance Sheet:** | | | | | | | | | | | | |
| Noncurrent asset | $ | — | $ | — | $ | — | $ | — | $ | 19 | $ | 17 |
| Current liability | | — | | — | | — | | — | | (2) | | (2) |
| Noncurrent liability | | (257) | | (210) | | (41) | | (37) | | (26) | | (24) |
| Net liability | $ | (257) | $ | (210) | $ | (41) | $ | (37) | $ | (9) | $ | (9) |
| **Amounts included in comprehensive income:** | | | | | | | | | | | | |
| Net actuarial loss (gain) | $ | 43 | $ | (3) | $ | 4 | $ | 5 | $ | 3 | $ | 3 |
| Net prior service credit | | 1 | | — | | — | | (9) | | — | | — |
| Amortization of net actuarial loss | | (17) | | (10) | | — | | — | | (1) | | (1) |
| Amortization of prior service credit | | — | | — | | 1 | | — | | — | | — |
| | $ | 27 | $ | (13) | $ | 5 | $ | (4) | $ | 2 | $ | 2 |
| **Amounts included in AOCL:*** | | | | | | | | | | | | |
| Net actuarial loss (gain) | $ | 239 | $ | 213 | $ | 5 | $ | 1 | $ | 15 | $ | 13 |
| Prior service cost | | 1 | | — | | (8) | | (9) | | — | | — |
| | $ | 240 | $ | 213 | $ | (3) | $ | (8) | $ | 15 | $ | 13 |

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are classified as Other Regulatory Assets or Other Regulatory Liabilities, respectively, as future recoverability is expected from retail customers.

Significant actuarial gains (losses) experienced that resulted in changes in projected benefit obligation included the following:

1 For the defined benefit pension plan, actuarial losses due to demographic experience, including assumption changes, were losses of $104 million and $88 million, and the changes between actual and expected return on plan assets were gains of

$61 million and $94 million for the years ended December 31, 2020 and 2019, respectively.

2 For the other postretirement benefits, actuarial losses due to demographic experience, including assumption changes, were losses of $5 million and $2 million, and the changes between actual and expected return on plan assets were gains of $1 million for each of the years ended December 31, 2020 and 2019, respectively.

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 | |
|---|---|---|---|---|---|---|
| | 2020 | 2019 | 2020 | 2019 | 2020 | 2019 |
| Service cost | $ 17 | $ 16 | $ 2 | $ 2 | $ — | $ — |
| Interest cost on benefit obligation | 31 | 34 | 2 | 3 | 1 | 1 |
| Expected return on plan assets | (44) | (40) | (2) | (2) | — | — |
| Amortization of prior service credit | — | — | (1) | — | — | — |
| Amortization of net actuarial loss | 17 | 10 | — | — | 1 | 1 |
| Curtailment gain | — | — | — | (2) | — | — |
| Net periodic benefit cost | $ 21 | $ 20 | $ 1 | $ 1 | $ 2 | $ 2 |

The following assumptions were used in determining benefit obligations and net period benefit costs:

| | Defined Benefit Pension Plan | | Other Postretirement Benefits | | Non-Qualified Benefit Plans | |
|---|---|---|---|---|---|---|
| | 2020 | 2019 | 2020 | 2019 | 2020 | 2019 |
| **Assumptions used to determine benefit obligations:** | | | | | | |
| Discount rate | 2.64 % | 3.43 % | 2.22% - 2.92 % | 3.19% - 3.47 % | 2.64 % | 3.43 % |
| Rate of compensation increase | 3.65 % | 3.65 % | 4.58 % | 4.58 % | 4.10 % | N/A |
| **Assumptions used to determine net periodic benefit cost:** | | | | | | |
| Discount rate | 3.43 % | 4.25 % | 3.19% - 3.47 % | 3.11% - 4.26 % | 3.43 % | 3.43 % |
| Rate of compensation increase | 3.65 % | 3.65 % | 4.58 % | 4.58 % | 4.10 % | N/A |
| Long-term rate of return on plan assets | 7.00 % | 7.00 % | 5.02 % | 5.88 % | N/A | N/A |

As of December 31, 2020, there are no liabilities with sensitivity to health care cost trend rates.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets, or a 0.25% reduction in the discount rate, would have the effect of increasing the 2020 net periodic pension expense by approximately $2 million and $3 million, respectively.

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 | | | | | |
|---|---|---|---|---|---|---|
| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 - 2030 |
| Defined benefit pension plan | $ 45 | $ 45 | $ 46 | $ 47 | $ 47 | $ 243 |
| Other postretirement benefits | 5 | 5 | 5 | 6 | 5 | 19 |
| Non-qualified benefit plans | 2 | 2 | 3 | 2 | 2 | 11 |
| Total | $ 52 | $ 52 | $ 54 | $ 55 | $ 54 | $ 273 |

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.

***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 to the 401(k) Plan 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 $26 million in 2020 and $25 million in 2019.

## NOTE 11: INCOME TAXES

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

| | Years Ended December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Current: | | |
| Federal | $ 6 | $ 9 |
| State and local | 17 | 12 |

| | | |
|---|---|---|
| | 23 | 21 |
| Deferred: | | |
| Federal | (22) | (2) |
| State and local | (1) | 8 |
| | (23) | 6 |
| Income tax expense | $ — | $ 27 |

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, | |
|---|---|---|
| | 2020 | 2019 |
| Federal statutory tax rate | 21.0 % | 21.0 % |
| Federal tax credits(1) | (20.5) | (13.4) |
| State and local taxes, net of federal tax benefit(2) | 10.1 | 6.5 |
| Flow through depreciation and cost basis differences | (4.9) | 1.5 |
| Reversal of excess deferred income tax(3) | (4.7) | (3.7) |
| Other | (1.0) | (0.7) |
| Effective tax rate | — % | 11.2 % |

(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 2030.

(2) In 2019, Oregon enacted HB 3427, which imposed a new gross receipts tax on companies with annual revenues in excess of $1 million and applies to tax years beginning on or after January 1, 2020. The legislation defines that the tax applies to commercial activities sourced in Oregon, less certain deductions. The resulting amount is taxed at 0.57%.

(3) The majority of excess deferred income taxes related to remeasurement under the Tax Cuts and Jobs Act (TCJA) is subject to Internal Revenue Service normalization rules and will be reversed over the remaining regulatory life of the assets using the average rate assumption method.

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

| | As of December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Deferred Income Tax Assets: | | |
| Employee benefits | $ 137 | $ 120 |
| Price risk management | 42 | 36 |
| Regulatory liabilities | 23 | 22 |

| | | |
|---|---|---|
| Tax credits | 77 | 64 |
| Depreciation and amortization | 329 | 315 |
| Other | 9 | 6 |
| Total Deferred Income Tax Assets | 617 | 563 |
| Deferred Income Tax Liabilities: | | |
| Depreciation and amortization | 834 | 812 |
| Regulatory assets | 130 | 105 |
| Price risk management | 12 | 10 |
| Other | 16 | 14 |
| Total Deferred Income Tax Liabilities | 992 | 941 |
| Accumulated Deferred Income Tax Liability, net | $ 375 | $ 378 |

As of December 31, 2020, PGE has federal credit carryforwards of $77 million, consisting of PTCs, which will expire at various dates through 2040. PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2020 and 2019 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2020, and 2019, PGE had no material 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.

In response to the TCJA, FERC issued a letter to Utilities requesting that the recipients either lower their rates to customers or show cause as to why they would elect not to do so. At PGE's request, FERC issued an order related to docket number EL18-109 on November 5, 2019 noting that PGE had shown cause as to why its transmission rate for its main transmission system should not be revised to reflect the reduced federal income tax rate due to the TCJA. However, PGE was required to update its transmission rate for its Colstrip transmission system, which PGE did on December 5, 2019. PGE's Power Operations (i.e., Marketing Function) is the sole customer of the Colstrip transmission system.

## 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 or 1,500 shares (based on fair value on the purchase date), 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, 2020, there were 241,281 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, 2020, there were 2,462,263 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. RSU activity is summarized in the following table:

| | Units | Weighted Average Grant Date Fair Value |
|---|---|---|
| Nonvested units as of December 31, 2018 | 428,913 | $ 38.43 |
| Granted | 210,555 | 49.06 |
| Forfeited | (9,041) | 41.68 |
| Vested | (167,037) | 37.52 |
| Nonvested units as of December 31, 2019 | 463,390 | 43.52 |
| Granted | 202,883 | 56.45 |
| Forfeited | (17,341) | 50.27 |
| Vested | (170,536) | 45.67 |
| Nonvested units as of December 31, 2020 | 478,396 | 48.00 |

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 2,737,180 shares remain available for future issuance as of December 31, 2020.

Outstanding RSUs provide for the payment of one Dividend Equivalent Right (DER) for each stock unit. Each DER represents an amount equal to dividends paid to shareholders on a share of PGE's common stock and vests on the same schedule as the related RSU. The DERs are settled in 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).

*Time-based RSUs* generally vest over a period of up to three years from 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 $1 million for the years ended December 31, 2020 and 2019.

*Performance-based RSUs* vest based on the extent to which performance goals are met at the end of a three-year performance period, subject to adjustment by the Compensation and Human Resources Committee of PGE's Board of Directors. The number of RSUs that may vest under grants awarded in 2018 is based on two equally-weighted metrics: i) actual return on equity relative to allowed return on equity; and ii) a relative total shareholder return (TSR) of PGE's common stock as compared to an index of peer companies during the performance period. Based on the attainment of the goals, the number of RSUs that vest can range from zero to 175% of the RSUs granted. The number of RSUs that may vest under grants awarded in 2019 and 2020 is based on three equally-weighted metrics: i) actual return on equity relative to allowed return on equity; ii) average EPS growth; and iii) power supply portfolio decarbonization—and relative TSR as a modifier to the total of the three equally-weighted metrics. Based on the attainment of the goals, the number of RSUs that vest can range from zero to 175% of the RSUs granted.

For return on equity, average EPS growth and carbon reduction metrics of the performance-based RSUs, fair value is measured based on the NYSE 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 with the following weighted average assumptions:

| | 2020 | 2019 |
|---|---|---|
| Risk-free interest rate | 1.4 % | 2.5 % |
| Expected term (in years) | 2.9 | 3.0 |
| Volatility | 13.5 % - 97.3 % | 14.8 % - 74.5 % |

There is no expected dividend yield used in the valuation, as it is assumed that all dividends distributed during the performance period are reinvested in the Company's underlying stock. 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 157.3%, 129.0%, and 69.0% of awarded performance-based RSUs for the respective 2020, 2019, and 2018 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $9 million for the year ended December 31, 2020 and $7 million for 2019.

*Stock-based compensation,* included in Administrative and General Expenses in the Statement of Income, was $11 million for the year ended December 31, 2020 and $9 million for 2019. Such amounts differ from those reported in Other Paid-in Capital 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 General 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 Stockholder equity of $2 million in both 2020 and 2019.

As of December 31, 2020, unrecognized stock-based compensation expense was $13 million, which is expected to be recognized over a weighted average period of one to three years. No stock-based compensation costs have been capitalized.

## NOTE 14: COMMITMENTS AND GUARANTEES

***Purchase Commitments***

As of December 31, 2020, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

| | Payments Due | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2021 | 2022 | 2023 | 2024 | 2025 | Thereafter | Total |
| Capital and other purchase commitments | $ 237 | $ 33 | $ 20 | $ 1 | $ 1 | $ 55 | $ 347 |
| Purchased power: | | | | | | | |
| Electricity purchases | 250 | 257 | 284 | 278 | 249 | 2,886 | 4,204 |
| Capacity contracts | 9 | 9 | 9 | 9 | 9 | — | 45 |
| Public utility districts | 21 | 19 | 18 | 17 | 17 | 39 | 131 |
| Natural gas | 57 | 42 | 37 | 43 | 43 | 578 | 800 |
| Coal and transportation | 27 | 27 | 27 | 27 | 27 | — | 135 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Total | $ 601 | $ 387 | $ 395 | $ 375 | $ 346 | $ 3,558 | $ 5,662 |

*Capital and other purchase commitments*—Certain commitments have been made for 2021 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 2052, 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:

1 Grant County PUD for the Priest Rapids and Wanapum Hydroelectric Projects, and

2 Douglas County PUD for the Wells Hydroelectric Project.

Under the Grant County 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. Under the Douglas County agreement, the Company is required to make 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 County's 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, 2020 | PGE's Average Share as of December 31, 2020 | | Contract Expiration | Total PGE Contract Costs | | |
|---|---|---|---|---|---|---|---|
| | | Output | Capacity | | 2020 | 2019 | 2018 |
| | | | (in MW) | | | | |
| Priest Rapids and Wanapum | $ 1,880 | 8.6 % | 163 | 2052 | $ 25 | $ 21 | $ 17 |
| Wells | 572 | 16.6 | 94 | 2028 | 23 | 16 | 11 |

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.

*Coal and transportation*—PGE had coal and related rail transportation agreements with take-or-pay provisions related to the Boardman coal-fired generation plant (Boardman) that expired in December 2020 in conjunction with the cessation of coal fired generation at Boardman. The Company has a coal agreement with take-or-pay provisions related to Colstrip Units 3 and 4 coal-fired generation plant (Colstrip) that expires in December 2025.

***Guarantees***

PGE enters into financial agreements, and purchase and sale agreements involving physical delivery of, both power and natural gas 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, 2020, 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: LEASES

PGE determines if an arrangement is a lease at inception and whether the arrangement is classified as an operating or finance lease. At commencement of the lease, PGE records a right-of-use (ROU) asset and lease liability in the Comparative Balance Sheet based on the present value of lease payments over the term of the arrangement. ROU assets represent the right to use an underlying asset for the lease term and lease liabilities represent PGE's obligation to make lease payments arising from the lease. If the implicit rate is not readily determinable in the contract, PGE uses its incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. Contract terms may include options to extend or terminate the lease, and, when the Company deems it is reasonably certain that PGE will exercise that option, it is included in the ROU asset and lease liability.

Lease expense is recognized on the Statement of Income in the appropriate rent expense account on the basis of actual amounts paid under leasing arrangements. For ratemaking purposes, recovery of cost-of-serviceis generally based on actual lease payments. Any material differences between lease expense and amounts recovered through customer prices is deferred as a regulatory asset or liability. Leased assets are not included in rate base.
PGE does not record leases with a term of 12-months or less in the Comparative Balance Sheet. Total short-term lease costs as of December 31, 2020 are immaterial. PGE has lease agreements with lease and non-lease components, which are accounted for separately.

The Company's leases relate primarily to the use of land, support facilities, gas storage, and power purchase agreements that rely on identified plant. Variable payments are generally related to gas storage and power purchase agreements for components dependent upon variable factors, such as energy production and property taxes, and are not included in the determination of the present value of lease payments.

The components of lease cost were as follows (in millions):

| | 2020 | 2019 |
|---|---|---|
| **Operating lease cost** | $ 8 | $ 7 |
| **Finance lease cost:** | | |
| Amortization of right-of-use assets | $ 5 | $ 3 |
| Interest on lease liabilities | 10 | 6 |
| Total finance lease cost | $ 15 | $ 9 |
| **Variable lease cost** | $ 12 | $ 19 |

Supplemental information related to amounts and presentation of leases in the Comparative Balance Sheet is presented below (in millions):

| | Comparative Balance Sheet Classification | December 31, 2020 | December 31, 2019 |
|---|---|---|---|
| **Operating Leases:** | | | |
| Operating lease right-of-use assets | Net Utility Plant | $ 44 | $ 51 |
| | | | |
| Current liabilities | Obligations Under Capital Leases - Current | $ 8 | $ 8 |
| Noncurrent liabilities | Obligations Under Capital Leases - Noncurrent | 36 | 43 |
| Total operating lease liabilities* | | $ 44 | $ 51 |
| **Finance Leases:** | | | |
| Finance lease right-of-use assets | Net Utility Plant | $ 145 | $ 150 |
| | | | |
| Current liabilities | Obligations Under Capital Leases - Current | $ 16 | $ 16 |
| Noncurrent liabilities | Obligations Under Capital Leases - Noncurrent | 129 | 135 |
| Total finance lease liabilities | | $ 145 | $ 151 |

*Included in lease liabilities are $25 million and $32 million related to power purchase agreements for the years ended December 31, 2020 and 2019, respectively.

Lease term and discount rates were as follows:

| | December 31, 2020 | December 31, 2019 |
|---|---|---|
| **Weighted Average Remaining Lease Term (in years)** | | |
| Operating leases | 26 | 24 |
| Finance leases | 28 | 29 |
| **Weighted Average Discount Rate** | | |
| Operating leases | 3.6 % | 3.5 % |
| Finance leases | 7.3 % | 7.3 % |

PGE’s gas storage finance lease contains five 10-year renewal periods which have not been included in the finance lease obligation.

As of December 31, 2020, maturities of lease liabilities were as follows (in millions):

| | Operating Leases | Finance Leases |
|---|---|---|

| | | | | |
|---|---|---|---|---|
| 2021 | $ | 8 | $ | 16 |
| 2022 | | 8 | | 16 |
| 2023 | | 8 | | 14 |
| 2024 | | 7 | | 14 |
| 2025 | | 1 | | 13 |
| Thereafter | | 45 | | 222 |
| Total lease payments | | 77 | | 295 |
| Less imputed interest | | (33) | | (150) |
| Total | $ | 44 | $ | 145 |

Supplemental cash flow information related to leases was as follows (in millions):

| | December 31, 2020 | | December 31, 2019 | |
|---|---|---|---|---|
| **Cash paid for amounts included in the measurement of lease liabilities:** | | | | |
| Operating cash flows from operating leases | $ | 8 | $ | 7 |
| Operating cash flows from finance leases | | 10 | | 5 |
| Financing cash flows from finance leases | | 6 | | 4 |
| **Right-of-use assets obtained in leasing arrangements:** | | | | |
| Operating leases | $ | — | $ | 56 |
| Finance leases | | — | | 154 |

As of December 31, 2020, PGE has an additional operating lease for an energy storage agreement that has not yet commenced with an estimated present value of future lease payments of $30 million. This lease is expected to commence in 2022 with a lease term of 20 years.

## NOTE 16: JOINTLY-OWNED PLANT

As of December 31, 2020, PGE had the following investments in jointly-owned plant (dollars in millions):

| | PGE Share | In-service Date | Plant In-service | | Accumulated Depreciation* | | Construction Work In Progress | |
|---|---|---|---|---|---|---|---|---|
| Colstrip | 20.00 % | 1986 | $ | 566 | $ | 387 | $ | 7 |
| Pelton/Round Butte | 66.67 % | 1958 / 1964 | | 283 | | 82 | | 7 |
| Total | | | $ | 849 | $ | 469 | $ | 14 |

* Excludes AROs and accumulated asset retirement removal costs.

Under the respective joint operating agreements for the generating facilities, each participating owner is responsible for financing its share of capital and operating expenses. 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.

The Company operated, and continues to have a 90% ownership interest in, Boardman, which ceased coal-fired operations during the fourth quarter of 2020. The Company has begun the initial steps toward decommissioning the facility. As of December 31, 2020, PGE's ARO liability for its 90% share of the decommissioning costs was $44 million.

## NOTE 17: 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.

### *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 2017. The ROD outlined the EPA's selected remediation plan for clean-up of the Portland Harbor site, which has an undiscounted 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. 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. Stakeholders have raised concerns that EPA's cost estimates are understated. 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.

A small group of PRPs performed pre-remedial design sampling to update baseline data and submitted the data in an updated evaluation report to the EPA for review. The evaluation report concluded that the conditions of the Portland Harbor Superfund site have improved substantially over the past ten years. In response, the EPA indicated that while it would use the data to inform implementation of the ROD, the EPA's conclusions remained materially unchanged. With the completion of pre-remedial design sampling, Portland Harbor is now in the remedial design phase, which consists of additional technical information and data collection to be used to design the expected remedial actions. Certain PRPs, not including PGE, have entered into consent agreements to perform remedial design and the EPA has indicated it will take the initial lead to perform remedial design on the remaining areas. The EPA announced on February 12, 2021 that 100% of Portland Harbor is under an active engineering design phase.

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 that are integral to the determination of such an allocation percentage, remedial design, a final allocation methodology, and data with regard to property specific activities and history of ownership of sites within Portland Harbor that will inform the precise boundaries for clean-up. It is probable that PGE will share in a portion of the costs related to Portland Harbor. However, based on the above facts and remaining uncertainties, PGE does not currently have sufficient information to reasonably estimate the amount, or range, of its potential liability or determine an allocation percentage that represents PGE's portion of the liability to clean-up Portland Harbor, although such costs could be material to PGE's financial position.

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 consist of the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, the state of Oregon, the Confederated Tribes of the Grand Ronde Community of Oregon, the Confederated Tribes of Siletz Indians, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS), and the Nez Perce Tribe.

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.

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 by the OPUC 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 if necessary, through customer prices. The mechanism established annual prudency reviews of environmental expenditures and third-party proceeds. Annual expenditures in excess of $6 million, excluding expenses related to contingent liabilities, are subject to an annual earnings test and would be ineligible for recovery to the extent PGE's actual regulated return on equity exceeds its return on equity as authorized by the OPUC in PGE's most recent general rate case. Under the PHERA mechanism in 2020, PGE incurred and deferred $6 million related to defense costs, net of an immaterial estimated refund as a result of PGE overearning in the regulated earnings test for this deferral. 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 plans to seek recovery of any costs resulting from the EPA's determination of liability for Portland Harbor through application of the PHERA. At this time, PGE is not recovering any Portland Harbor cost from the PHERA through customer prices.

***Trojan Investment Recovery Class Actions***

In 1993, PGE closed 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 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 (Circuit Court); and ii) Morgan v. Portland General Electric Company, Marion County Circuit Court. The class action lawsuits sought 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, 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 lifted the abatement on the class action proceedings and heard oral argument on the Company's motion for Summary Judgment. In 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. The plaintiffs subsequently appealed the Circuit Court dismissal to the Court of Appeals for the state of Oregon.

In November 2019, the Court of Appeals issued an opinion that affirmed the Circuit Court dismissal. On December 30, 2019, the plaintiffs filed a motion for reconsideration, which the Court of Appeals denied on February 4, 2020.

On April 7, 2020, the Plaintiffs filed a petition with the OSC requesting review and reversal of the Court of Appeals opinion. On July 16, 2020, the OSC issued an order that denied the petition for review.

***Deschutes River Alliance Clean Water Act Claims***

In August 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 March and April 2018, DRA and PGE filed cross-motions for summary judgment and PGE and CTWS, which co-own the Project, filed separate motions to dismiss. CTWS initially appeared as a friend of the court, but subsequently was found to be a necessary party to the lawsuit and joined as a defendant.

In August 2018, the U.S. District Court of the District of Oregon (District Court) 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 District Court 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.

In October 2018, DRA filed an appeal, and PGE and CTWS filed cross-appeals, to the Ninth Circuit Court of Appeals. The appeals are fully briefed and oral argument is set for May 7, 2021..

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

***Shareholder Lawsuits***

During September and October, 2020, three putative class action complaints were filed in U.S. District Court for the District of Oregon against PGE and certain of its officers, captioned *Hessel v. Portland General Electric Co.*, No. 20-cv-01523 (*"Hessel"*), *Cannataro v. Portland General Electric Co.*, No. 3:20-cv-01583 (*"Cannataro"*), and *Public Employees' Retirement System of Mississippi v. Portland General Electric Co.*, No. 20-cv-01786 (*"PERS of Mississippi"*). Two of these actions were filed on behalf of purported purchasers of PGE stock between April 24, 2020, and August 24, 2020; a third action was filed on behalf of purported purchasers of PGE stock between February 13, 2020, and August 24, 2020.

During the fourth quarter of 2020, the plaintiff in *Hessel* voluntarily dismissed his case and the court consolidated *Cannataro* and *PERS of Mississippi* into a single case captioned *In re Portland General Electric Company Securities Litigation* and appointed Public Employees' Retirement System of Mississippi lead plaintiff ("Lead Plaintiff"). On January 11, 2021, Lead Plaintiff filed an amended complaint asserting causes of action arising under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 for alleged misstatements and omissions regarding, among other things, PGE's alleged lack of sufficient internal controls and risks associated with PGE's trading activity in wholesale electric markets, purportedly on behalf of purchasers of PGE stock between February 13, 2020, and August 24, 2020. The complaint demands a jury trial and seeks compensatory damages of an unspecified amount and reimbursement of plaintiffs' costs, and attorneys' and expert fees.

The Company intends to vigorously defend against the lawsuit. Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

***Putative Shareholder Derivative Lawsuits***

On January 26, 2021, a putative shareholder derivative lawsuit, was filed in Multnomah County Circuit Court, Oregon, captioned *Shimberg v. Pope*, No. 21- cv-02957, against one current and one former PGE executive and several members of the Company's Board of Directors (collectively, the "Individual Defendants") and naming the Company as a nominal defendant only. The plaintiff asserts a claim for alleged breaches of fiduciary duties, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the Individual Defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks damages to be awarded to the Company of not less than $10 million, equitable relief to remedy the alleged breaches of fiduciary duty, and an award of plaintiff's attorneys' fees and costs.

Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

On March 17, 2021, a putative shareholder derivative lawsuit was filed in U.S. District Court for the District of Oregon, captioned *JS Halberstam Irrevocable Grantor Trust v. Davis*, No. 3:21-cv-00413-SI, against one current and one former PGE executive and all members of the Company's Board of Directors. The plaintiff asserts claims for alleged breaches of fiduciary duties, waste of corporate assets, contribution and indemnification, aiding and abetting, and gross mismanagement, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks equitable relief to remedy and prevent future alleged breaches of fiduciary duty, and an award of plaintiff's attorneys' fees and costs.

Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

On April 7, 2021, a putative shareholder derivative lawsuit was filed in Multnomah County Circuit Court, Oregon, captioned, *Ashabraner v. Pope*, 21-cv-13698, against one current and one former PGE executive and several members of the Company's Board of Directors. The plaintiff asserts a claim for alleged breaches of fiduciary duties, purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks damages to be awarded to the Company, equitable relief, and an award of plaintiff's attorneys' fees and costs.

Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible 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.

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

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

| Line No. | Item (a) | Unrealized Gains and Losses on Available-for-Sale Securities (b) | Minimum Pension Liability adjustment (net amount) (c) | Foreign Currency Hedges (d) | Other Adjustments (e) |
|---|---|---|---|---|---|
| 1 | Balance of Account 219 at Beginning of Preceding Year | | | | ( 6,431,626) |
| 2 | Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income | | | | ( 3,183,476) |
| 3 | Preceding Quarter/Year to Date Changes in Fair Value | | | | |
| 4 | Total (lines 2 and 3) | | | | ( 3,183,476) |
| 5 | Balance of Account 219 at End of Preceding Quarter/Year | | | | ( 9,615,102) |
| 6 | Balance of Account 219 at Beginning of Current Year | | | | ( 9,615,102) |
| 7 | Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income | | | | ( 1,489,803) |
| 8 | Current Quarter/Year to Date Changes in Fair Value | | | | |
| 9 | Total (lines 7 and 8) | | | | ( 1,489,803) |
| 10 | Balance of Account 219 at End of Current Quarter/Year | | | | ( 11,104,905) |

## 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) | | ( 6,432,434) | [redacted] | [redacted] |
| 2 | | | ( 3,183,476) | [redacted] | [redacted] |
| 3 | | | | [redacted] | [redacted] |
| 4 | | | ( 3,183,476) | 213,848,540 | 210,665,064 |
| 5 | ( 808) | | ( 9,615,910) | [redacted] | [redacted] |
| 6 | ( 808) | | ( 9,615,910) | [redacted] | [redacted] |
| 7 | | | ( 1,489,803) | [redacted] | [redacted] |
| 8 | | | | [redacted] | [redacted] |
| 9 | | | ( 1,489,803) | 154,620,730 | 153,130,927 |
| 10 | ( 808) | | ( 11,105,713) | [redacted] | [redacted] |

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

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

Comprised of the net amount of the actuarial valuation of $(2,396,295) of non-qualified benefit plans net of taxes of $658,981 and reclassification of stranded tax effects due to Tax Reform of $(1,446,162).

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

Comprised of the net amount of the actuarial valuation of $(2,054,894) of non-qualified benefit plans net of taxes of $565,091.

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) | 9,353,889,754 | 9,353,889,754 |
| 4 | Property Under Capital Leases | 188,767,638 | 188,767,638 |
| 5 | Plant Purchased or Sold | | |
| 6 | Completed Construction not Classified | 1,463,893,390 | 1,463,893,390 |
| 7 | Experimental Plant Unclassified | | |
| 8 | Total (3 thru 7) | 11,006,550,782 | 11,006,550,782 |
| 9 | Leased to Others | | |
| 10 | Held for Future Use | 8,359,324 | 8,359,324 |
| 11 | Construction Work in Progress | 430,009,860 | 430,009,860 |
| 12 | Acquisition Adjustments | | |
| 13 | Total Utility Plant (8 thru 12) | 11,444,919,966 | 11,444,919,966 |
| 14 | Accum Prov for Depr, Amort, & Depl | 4,871,352,378 | 4,871,352,378 |
| 15 | Net Utility Plant (13 less 14) | 6,573,567,588 | 6,573,567,588 |
| 16 | Detail of Accum Prov for Depr, Amort & Depl | | |
| 17 | In Service: | | |
| 18 | Depreciation | 4,483,327,657 | 4,483,327,657 |
| 19 | Amort & Depl of Producing Nat Gas Land/Land Right | | |
| 20 | Amort of Underground Storage Land/Land Rights | | |
| 21 | Amort of Other Utility Plant | 388,024,721 | 388,024,721 |
| 22 | Total In Service (18 thru 21) | 4,871,352,378 | 4,871,352,378 |
| 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) | 4,871,352,378 | 4,871,352,378 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original (2) [ ] A Resubmission | / / | End of 2020/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. |
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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<br>(2) [ ] A Resubmission | / / | End of 2020/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<br>(2) [ ] A Resubmission | / / | End of 2020/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. |
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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 | 195,264,816 | 7,956,109 |
| 4 | (303) Miscellaneous Intangible Plant | 563,164,236 | 29,473,714 |
| 5 | TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4) | 758,429,052 | 37,429,823 |
| 6 | 2. PRODUCTION PLANT | | |
| 7 | A. Steam Production Plant | | |
| 8 | (310) Land and Land Rights | 4,161,625 | 90 |
| 9 | (311) Structures and Improvements | 258,900,489 | -6,679 |
| 10 | (312) Boiler Plant Equipment | 614,310,310 | 14,472,002 |
| 11 | (313) Engines and Engine-Driven Generators | | |
| 12 | (314) Turbogenerator Units | 188,750,229 | 78,190 |
| 13 | (315) Accessory Electric Equipment | 55,267,293 | 448,812 |
| 14 | (316) Misc. Power Plant Equipment | 15,016,041 | -114,420 |
| 15 | (317) Asset Retirement Costs for Steam Production | 75,980,571 | 1,039,281 |
| 16 | TOTAL Steam Production Plant (Enter Total of lines 8 thru 15) | 1,212,386,558 | 15,917,276 |
| 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 | 84,069,521 | 7,871,611 |
| 29 | (332) Reservoirs, Dams, and Waterways | 358,769,141 | 1,334,916 |
| 30 | (333) Water Wheels, Turbines, and Generators | 76,994,707 | 3,288,184 |
| 31 | (334) Accessory Electric Equipment | 31,601,534 | 3,036,840 |
| 32 | (335) Misc. Power PLant Equipment | 21,315,447 | 514,060 |
| 33 | (336) Roads, Railroads, and Bridges | 15,391,900 | 624,094 |
| 34 | (337) Asset Retirement Costs for Hydraulic Production | 5,128 | |
| 35 | TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34) | 594,201,281 | 16,669,705 |
| 36 | D. Other Production Plant | | |
| 37 | (340) Land and Land Rights | 26,960,038 | |
| 38 | (341) Structures and Improvements | 230,103,104 | 2,333,557 |
| 39 | (342) Fuel Holders, Products, and Accessories | 295,883,557 | 92,640 |
| 40 | (343) Prime Movers | | |
| 41 | (344) Generators | 2,406,329,698 | 157,837,227 |
| 42 | (345) Accessory Electric Equipment | 121,136,967 | 659,921 |
| 43 | (346) Misc. Power Plant Equipment | 44,080,984 | 2,340,137 |
| 44 | (347) Asset Retirement Costs for Other Production | 22,576,353 | 2,766,486 |
| 45 | TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44) | 3,147,070,701 | 166,029,968 |
| 46 | TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45) | 4,953,658,540 | 198,616,949 |

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 | 17,269,685 | 31,759 |
| 49 | (352) Structures and Improvements | 30,274,032 | 502,940 |
| 50 | (353) Station Equipment | 499,772,267 | 75,850,794 |
| 51 | (354) Towers and Fixtures | 48,824,328 | 7,016,123 |
| 52 | (355) Poles and Fixtures | 83,364,423 | 17,796,023 |
| 53 | (356) Overhead Conductors and Devices | 169,438,106 | 31,239,961 |
| 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) | 849,263,282 | 132,437,600 |
| 59 | 4. DISTRIBUTION PLANT | | |
| 60 | (360) Land and Land Rights | 19,099,994 | 40,776 |
| 61 | (361) Structures and Improvements | 46,326,090 | 696,987 |
| 62 | (362) Station Equipment | 559,680,235 | 63,208,353 |
| 63 | (363) Storage Battery Equipment | 393,191 | 5,924 |
| 64 | (364) Poles, Towers, and Fixtures | 420,260,020 | 51,280,987 |
| 65 | (365) Overhead Conductors and Devices | 664,059,809 | 43,017,178 |
| 66 | (366) Underground Conduit | 29,515,629 | 1,454,076 |
| 67 | (367) Underground Conductors and Devices | 907,226,219 | 26,048,248 |
| 68 | (368) Line Transformers | 469,865,714 | 20,208,641 |
| 69 | (369) Services | 495,383,566 | 26,139,632 |
| 70 | (370) Meters | 185,286,768 | 17,387,057 |
| 71 | (371) Installations on Customer Premises | 1,749,713 | 630,425 |
| 72 | (372) Leased Property on Customer Premises | | |
| 73 | (373) Street Lighting and Signal Systems | 117,253,253 | 18,298,538 |
| 74 | (374) Asset Retirement Costs for Distribution Plant | 476,732 | |
| 75 | TOTAL Distribution Plant (Enter Total of lines 60 thru 74) | 3,916,576,933 | 268,416,822 |
| 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 | 9,622,353 | -49,999 |
| 87 | (390) Structures and Improvements | 151,444,048 | 5,665,551 |
| 88 | (391) Office Furniture and Equipment | 160,507,769 | 14,937,201 |
| 89 | (392) Transportation Equipment | 78,457,262 | 8,376,552 |
| 90 | (393) Stores Equipment | 3,877,884 | 490,280 |
| 91 | (394) Tools, Shop and Garage Equipment | 23,093,384 | 1,601,629 |
| 92 | (395) Laboratory Equipment | 8,901,072 | 5,846,080 |
| 93 | (396) Power Operated Equipment | 44,630,769 | 3,614,453 |
| 94 | (397) Communication Equipment | 179,228,998 | 21,995,221 |
| 95 | (398) Miscellaneous Equipment | 1,295,282 | -417 |
| 96 | SUBTOTAL (Enter Total of lines 86 thru 95) | 661,058,821 | 62,476,551 |
| 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) | 661,124,110 | 62,476,551 |
| 100 | TOTAL (Accounts 101 and 106) | 11,139,051,917 | 699,377,745 |
| 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) | 11,139,051,917 | 699,377,745 |

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 |
| 1,610,806 | 438,909 | | 202,049,028 | | 3 |
| 41,267,619 | | | 551,370,331 | | 4 |
| 42,878,425 | 438,909 | | 753,419,359 | | 5 |
| | | | | | 6 |
| | | | | | 7 |
| | | -832,853 | 3,328,862 | | 8 |
| 108,779,931 | -95,531 | -32,720,154 | 117,298,194 | | 9 |
| 347,558,126 | -452,059 | -9,965,453 | 270,806,674 | | 10 |
| | | | | | 11 |
| 115,959,180 | -259 | | 72,868,980 | | 12 |
| 31,570,281 | -33,854 | -159,711 | 23,952,259 | | 13 |
| 8,240,304 | -45,881 | -12,716 | 6,602,720 | | 14 |
| 33,910,136 | -8,198,453 | | 34,911,263 | | 15 |
| 646,017,958 | -8,826,037 | -43,690,887 | 529,768,952 | | 16 |
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| | | | | | 26 |
| | | | 6,053,903 | | 27 |
| 11,427 | -1,445,242 | | 90,484,463 | | 28 |
| | -1,638,644 | | 358,465,413 | | 29 |
| | -1,468,200 | | 78,814,691 | | 30 |
| | -352,319 | | 34,286,055 | | 31 |
| | -3,426,212 | | 18,403,295 | | 32 |
| | -318,123 | | 15,697,871 | | 33 |
| | | | 5,128 | | 34 |
| 11,427 | -8,648,740 | | 602,210,819 | | 35 |
| | | | | | 36 |
| | -2,855,604 | | 24,104,434 | | 37 |
| 37,597 | -972,203 | 42,740,467 | 274,167,328 | | 38 |
| 49,774 | -7,418,947 | | 288,507,476 | | 39 |
| | | | | | 40 |
| 3,989,761 | -5,047,172 | | 2,555,129,992 | | 41 |
| 218,494 | -695,947 | | 120,882,447 | | 42 |
| 131,152 | -678,130 | | 45,611,839 | | 43 |
| | | | 25,342,839 | | 44 |
| 4,426,778 | -17,668,003 | 42,740,467 | 3,333,746,355 | | 45 |
| 650,456,163 | -35,142,780 | -950,420 | 4,465,726,126 | | 46 |

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

| Retirements (d) | Adjustments (e) | Transfers (f) | Balance at End of Year (g) | | Line No. |
|---|---|---|---|---|---|
| | | | | | 47 |
| | -9,638 | | 17,291,806 | | 48 |
| | -362,293 | | 30,414,679 | | 49 |
| 8,207,803 | -2,007,165 | | 565,408,093 | | 50 |
| 1,924,617 | | | 53,915,834 | | 51 |
| 68,469 | -71,735 | | 101,020,242 | | 52 |
| 1,614,470 | -153,341 | | 198,910,256 | | 53 |
| | | | | | 54 |
| | | | | | 55 |
| | | | 286,332 | | 56 |
| | | | 34,109 | | 57 |
| 11,815,359 | -2,604,172 | | 967,281,351 | | 58 |
| | | | | | 59 |
| | -11,664 | | 19,129,106 | | 60 |
| 499,530 | -251,112 | | 46,272,435 | | 61 |
| 4,300,447 | -1,752,759 | | 616,835,382 | | 62 |
| | | | 399,115 | | 63 |
| 3,779,706 | -8,733,490 | | 459,027,811 | | 64 |
| 509,953 | -3,723,776 | | 702,843,258 | | 65 |
| | -33,689 | | 30,936,016 | | 66 |
| 154,306 | -6,321,237 | | 926,798,924 | | 67 |
| 394,231 | -1,712,575 | | 487,967,549 | | 68 |
| 64,064 | -1,453,907 | | 520,005,227 | | 69 |
| 6,727,172 | -482,584 | | 195,464,069 | | 70 |
| | | | 2,380,138 | | 71 |
| | | | | | 72 |
| 2,846,065 | -4,493,789 | | 128,211,937 | | 73 |
| | | | 476,732 | | 74 |
| 19,275,474 | -28,970,582 | | 4,136,747,699 | | 75 |
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| | | | | | 85 |
| | | | 9,572,354 | | 86 |
| 575,749 | -1,075,200 | 237,416 | 155,696,066 | | 87 |
| 22,640,354 | 159,191 | | 152,963,807 | | 88 |
| 6,062,996 | -420,797 | 481,788 | 80,831,809 | | 89 |
| 87,819 | | | 4,280,345 | | 90 |
| 1,024,022 | -25,441 | | 23,645,550 | | 91 |
| 743,541 | | | 14,003,611 | | 92 |
| 6,818,876 | | -481,788 | 40,944,558 | | 93 |
| 849,485 | -290,037 | | 200,084,697 | | 94 |
| 6,704 | | | 1,288,161 | | 95 |
| 38,809,546 | -1,652,284 | 237,416 | 683,310,958 | | 96 |
| | | | | | 97 |
| | | | 65,289 | | 98 |
| 38,809,546 | -1,652,284 | 237,416 | 683,376,247 | | 99 |
| 763,234,967 | -67,930,909 | -713,004 | 11,006,550,782 | | 100 |
| | | | | | 101 |
| | | | | | 102 |
| | | | | | 103 |
| 763,234,967 | -67,930,909 | -713,004 | 11,006,550,782 | | 104 |

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

***Schedule Page: 204 Line No.: 32 Column: e***
Includes activities of capitalized lease assets.
***Schedule Page: 204 Line No.: 37 Column: e***
Includes activities of capitalized lease assets.
***Schedule Page: 204 Line No.: 39 Column: e***
Includes activities of capitalized lease assets.
***Schedule Page: 204 Line No.: 41 Column: e***
Includes activities of capitalized lease assets.
***Schedule Page: 204 Line No.: 87 Column: e***
Includes activities of capitalized lease assets.
***Schedule Page: 204 Line No.: 104 Column: d***
Includes $631.5M retirement of the Boardman coal plant in 4Q 2020.
***Schedule Page: 204 Line No.: 104 Column: e***
Includes $(41.5)M adjustments to correctly classify cost of removal charges improperly classified as Utility Plant in prior periods.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | // | End of 2020/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) |
|---|---|---|---|---|---|
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| 47 | TOTAL | | | | |

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

## ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

| Line No. | Description and Location Of Property (a) | Date Originally Included in This Account (b) | Date Expected to be used in Utility Service (c) | Balance at End of Year (d) |
|---|---|---|---|---|
| 1 | Land and Rights: | | | |
| 2 | Damascus, Clackamas County, OR | 2007 | Future | 543,591 |
| 3 | Sewell, Washington County, OR | 2008 | Future | 2,869,529 |
| 4 | Sewell Easement, Washington County, OR | 2009 | Future | 331,186 |
| 5 | Evergreen, Washington County, OR | 2019 | Future | 3,600,000 |
| 6 | Boardman, Morrow County, OR | 2020 | Future | 832,853 |
| 7 | Other Land and Land Rights | Various | Various | 182,165 |
| 8 | | | | |
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| 21 | Other Property: | | | |
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| 44 | | | | |
| 45 | | | | |
| 46 | | | | |
| 47 | Total | | | 8,359,324 |

## 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 | Build Integrated Operations Center | 109,122,893 |
| 2 | Repower Faraday Units 1-5 | 74,212,574 |
| 3 | Substation Communication Upgrade | 27,560,149 |
| 4 | Build Butler Substation | 18,104,180 |
| 5 | Roseway Substation Expansion | 18,003,672 |
| 6 | Advanced Distribution Management System Upgrade | 17,488,039 |
| 7 | Upgrade Physical Access Control System | 12,674,920 |
| 8 | Build Evergreen Substation | 12,589,326 |
| 9 | Willbridge Substation Conversion | 9,041,729 |
| 10 | Brookwood Substation Conversion | 8,539,069 |
| 11 | Build Helvetia Substation | 7,918,308 |
| 12 | Colstrip Coal Capital Project | 7,858,593 |
| 13 | Marquam Substation Feeder Addition | 7,254,609 |
| 14 | Hydro Control System Upgrade | 7,251,677 |
| 15 | Harborton Reliability Project | 7,460,287 |
| 16 | Distribution System Construction | 4,357,198 |
| 17 | Horizon Substation Transformer Installation | 3,655,445 |
| 18 | St. Mary's West Substation System Protection Upgrade | 3,595,653 |
| 19 | Build Sherwood Training Center | 3,304,414 |
| 20 | Energy Storage System | 3,209,071 |
| 21 | Blue Lake Substation Upgrade | 3,117,272 |
| 22 | South Milliken Distribution Line Rebuild | 3,011,243 |
| 23 | River District Infrastructure - Install Vaults and Conduits | 2,947,132 |
| 24 | Arleta-Holgate Conversion | 2,640,166 |
| 25 | Centennial Substation Upgrades | 2,609,511 |
| 26 | Pelton Round Butte Mitigation Enhancement Fund | 2,532,257 |
| 27 | Stephens Substation Conversion | 2,398,768 |
| 28 | Orenco Substation Rebuild | 2,208,085 |
| 29 | Small Generator/Qualified Facility (QF) Interconnection | 1,938,850 |
| 30 | Distribution Line Construction | 1,882,874 |
| 31 | Carty/Boardman Separation Project | 1,882,802 |
| 32 | Restore Beaver GT Unit 5 | 1,815,035 |
| 33 | Upgrade IVR System | 1,604,348 |
| 34 | Distributed Control Software Upgrade | 1,577,547 |
| 35 | Replace Exhaust Frame and Diffuser | 1,558,942 |
| 36 | Install Load Bank | 1,358,029 |
| 37 | Replace or Rewind Failed Transformers | 1,268,202 |
| 38 | Upgrade Excitation System | 1,114,170 |
| 39 | Canyon Substation Upgrade | 1,020,442 |
| 40 | | |
| 41 | Minor Projects, <$1 million, represents 7% of the Total CWIP Balance | 28,322,379 |
| 42 | | |
| 43 | TOTAL | 430,009,860 |

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

**_Schedule Page: 216     Line No.: 12     Column: b_**

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

**_Schedule Page: 216     Line No.: 26     Column: b_**

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.

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 | 4,914,258,659 | 4,914,258,659 | | |
| 2 | Depreciation Provisions for Year, Charged to | | | | |
| 3 | (403) Depreciation Expense | 315,333,112 | 315,333,112 | | |
| 4 | (403.1) Depreciation Expense for Asset Retirement Costs | -3,966,273 | -3,966,273 | | |
| 5 | (413) Exp. of Elec. Plt. Leas. to Others | | | | |
| 6 | Transportation Expenses-Clearing | 6,325,668 | 6,325,668 | | |
| 7 | Other Clearing Accounts | 67,151 | 67,151 | | |
| 8 | Other Accounts (Specify, details in footnote): | | | | |
| 9 | | | | | |
| 10 | TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9) | 317,759,658 | 317,759,658 | | |
| 11 | Net Charges for Plant Retired: | | | | |
| 12 | Book Cost of Plant Retired | 686,212,927 | 686,212,927 | | |
| 13 | Cost of Removal | 10,841,489 | 10,841,489 | | |
| 14 | Salvage (Credit) | 2,161,538 | 2,161,538 | | |
| 15 | TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14) | 694,892,878 | 694,892,878 | | |
| 16 | Other Debit or Cr. Items (Describe, details in footnote): | -22,404,703 | -22,404,703 | | |
| 17 | | | | | |
| 18 | Book Cost or Asset Retirement Costs Retired | -31,393,079 | -31,393,079 | | |
| 19 | Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18) | 4,483,327,657 | 4,483,327,657 | | |
| | **Section B. Balances at End of Year According to Functional Classification** | | | | |
| 20 | Steam Production | 380,845,848 | 380,845,848 | | |
| 21 | Nuclear Production | | | | |
| 22 | Hydraulic Production-Conventional | 274,374,882 | 274,374,882 | | |
| 23 | Hydraulic Production-Pumped Storage | | | | |
| 24 | Other Production | 987,247,487 | 987,247,487 | | |
| 25 | Transmission | 372,753,724 | 372,753,724 | | |
| 26 | Distribution | 2,181,668,233 | 2,181,668,233 | | |
| 27 | Regional Transmission and Market Operation | | | | |
| 28 | General | 286,437,483 | 286,437,483 | | |
| 29 | TOTAL (Enter Total of lines 20 thru 28) | 4,483,327,657 | 4,483,327,657 | | |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

***Schedule Page: 219 Line No.: 12 Column: c***

$631.5M due to retirement of Boardman Coal Plant in Q4 2020.

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

Other Debit or Credit items as follows:
-$(41.5)M Reduction to accumulated reserve with a corresponding offset to Utility Plant to correctly classify cost of removal charges improperly classified as Utility Plant in prior periods.

-$15.9M Due to reclassification of expected Boardman Salvage proceeds not yet realized from accumulated reserve to other regulatory liabilities (254.3).

-$2.4M Due to losses on retirements of utility plant.

-$0.7M Due to other reserve transfers and adjustments.

***Schedule Page: 219 Line No.: 18 Column: c***

Retirement of Boardman Asset Retirement Cost balance.

# 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 | | | 79,877,869 |
| 4 | Sub - TOTAL | | | 79,878,869 |
| 5 | | | | |
| 6 | Salmon Springs Hospitality Group | | | |
| 7 | Common Stock | 04/09/98 | | 10,000 |
| 8 | Equity in Earnings | | | 14,994 |
| 9 | Sub - TOTAL | | | 24,994 |
| 10 | | | | |
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| 41 | | | | |
| 42 | Total Cost of Account 123.1 $ 77,539,661 | | TOTAL | 79,903,863 |

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 |
| 2,791,607 | | 82,669,476 | | 3 |
| 2,791,607 | | 82,670,476 | | 4 |
| | | | | 5 |
| | | | | 6 |
| | | 10,000 | | 7 |
| -593,516 | -14,994 | -593,516 | | 8 |
| -593,516 | -14,994 | -583,516 | | 9 |
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| | | | | 40 |
| | | | | 41 |
| 2,198,091 | -14,994 | 82,086,960 | | 42 |

## MATERIALS AND SUPPLIES

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

| Line No. | Account (a) | Balance Beginning of Year (b) | Balance End of Year (c) | Department or Departments which Use Material (d) |
|---|---|---|---|---|
| 1 | Fuel Stock (Account 151) | 34,191,533 | 17,886,804 | Generation |
| 2 | Fuel Stock Expenses Undistributed (Account 152) | | | |
| 3 | Residuals and Extracted Products (Account 153) | | | |
| 4 | Plant Materials and Operating Supplies (Account 154) | | | |
| 5 | Assigned to - Construction (Estimated) | 18,665,272 | 21,101,356 | Transmission & Dis |
| 6 | Assigned to - Operations and Maintenance | | | |
| 7 | Production Plant (Estimated) | 23,724,986 | 14,628,422 | Generation |
| 8 | Transmission Plant (Estimated) | 225,427 | 570,226 | Transmission |
| 9 | Distribution Plant (Estimated) | 7,083,996 | 8,054,839 | Distribution |
| 10 | Regional Transmission and Market Operation Plant (Estimated) | | | |
| 11 | Assigned to - Other (provide details in footnote) | 2,252,410 | 1,875,277 | Power Operations |
| 12 | TOTAL Account 154 (Enter Total of lines 5 thru 11) | 51,952,091 | 46,230,120 | |
| 13 | Merchandise (Account 155) | | | |
| 14 | Other Materials and Supplies (Account 156) | | | |
| 15 | Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util) | | | |
| 16 | Stores Expense Undistributed (Account 163) | 3,657,581 | 2,688,473 | |
| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | TOTAL Materials and Supplies (Per Balance Sheet) | 89,801,205 | 66,805,397 | |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

***Schedule Page: 227 Line No.: 1 Column: c***

Reduction primarily due to closure of Boardman plant at the end of October 2020.

***Schedule Page: 227 Line No.: 7 Column: c***

Reduction primarily due to the closure of the Boardman plant at the end of October 2020 with its remaining inventory written off to account 254.

***Schedule Page: 227 Line No.: 11 Column: b***

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

***Schedule Page: 227 Line No.: 11 Column: c***

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) | 2021 No. (d) | 2021 Amt. (e) |
|---|---|---|---|---|---|
| 1 | Balance-Beginning of Year | 70,120.00 | | 10,028.00 | |
| 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 | 785.00 | | | |
| 19 | Other: | | | | |
| 20 | | | | | |
| 21 | Cost of Sales/Transfers: | | | | |
| 22 | | | | | |
| 23 | | | | | |
| 24 | | | | | |
| 25 | | | | | |
| 26 | | | | | |
| 27 | | | | | |
| 28 | Total | | | | |
| 29 | Balance-End of Year | 69,335.00 | | 10,028.00 | |
| 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) | | 3 | | |
| 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.

| 2022 | | 2023 | | Future Years | | Totals | | Line No. |
|---|---|---|---|---|---|---|---|---|
| No. (f) | Amt. (g) | No. (h) | Amt. (i) | No. (j) | Amt. (k) | No. (l) | Amt. (m) | |
| 10,032.00 | | 10,030.00 | | 95,300.00 | | 195,510.00 | | 1 |
| | | | | | | | | 2 |
| | | | | | | | | 3 |
| | | | | 1,321.00 | | 1,321.00 | | 4 |
| | | | | | | | | 5 |
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| | | | | | | | | 17 |
| | | | | | | 785.00 | | 18 |
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| 10,032.00 | | 10,030.00 | | 96,621.00 | | 196,046.00 | | 29 |
| | | | | | | | | 30 |
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| | | | | | | | | |
| 193.15 | | 193.15 | | 3,042.95 | | 4,823.84 | | 36 |
| | | | | | | | | 37 |
| | | | | | | | | 38 |
| | | | | 193.15 | | 386.30 | | 39 |
| 193.15 | | 193.15 | | 2,849.80 | | 4,437.54 | | 40 |
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## 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) | 2021 No. (d) | 2021 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 | | | | | |
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| 13 | | | | | |
| 14 | | | | | |
| 15 | Total | | | | |
| 16 | | | | | |
| 17 | Relinquished During Year: | | | | |
| 18 | Charges to Account 509 | | | | |
| 19 | Other: | | | | |
| 20 | | | | | |
| 21 | Cost of Sales/Transfers: | | | | |
| 22 | | | | | |
| 23 | | | | | |
| 24 | | | | | |
| 25 | | | | | |
| 26 | | | | | |
| 27 | | | | | |
| 28 | Total | | | | |
| 29 | Balance-End of Year | | | | |
| 30 | | | | | |
| 31 | Sales: | | | | |
| 32 | Net Sales Proceeds(Assoc. Co.) | | | | |
| 33 | Net Sales Proceeds (Other) | | | | |
| 34 | Gains | | | | |
| 35 | Losses | | | | |
| | Allowances Withheld (Acct 158.2) | | | | |
| 36 | Balance-Beginning of Year | | | | |
| 37 | Add: Withheld by EPA | | | | |
| 38 | Deduct: Returned by EPA | | | | |
| 39 | Cost of Sales | | | | |
| 40 | Balance-End of Year | | | | |
| 41 | | | | | |
| 42 | Sales: | | | | |
| 43 | Net Sales Proceeds (Assoc. Co.) | | | | |
| 44 | Net Sales Proceeds (Other) | | | | |
| 45 | Gains | | | | |
| 46 | Losses | | | | |

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



Allowances (Accounts 158.1 and 158.2) (Continued)

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

| 2022 | | 2023 | | Future Years | | Totals | | Line No. |
|---|---|---|---|---|---|---|---|---|
| No. (f) | Amt. (g) | No. (h) | Amt. (i) | No. (j) | Amt. (k) | No. (l) | Amt. (m) | |
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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 | | | | | | |
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| 19 | | | | | | |
| 20 | TOTAL | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2020/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; | 421,121,474 | 3,397,140 | | 1,900,000 | 95,486,982 |
| 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 | | | | | | |
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| 45 | | | | | | |
| 46 | | | | | | |
| 47 | | | | | | |
| 48 | | | | | | |
| 49 | TOTAL | 421,121,474 | 3,397,140 | | 1,900,000 | 95,486,982 |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

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

$1,900,000 - Recovery of Trojan decommissioning costs included in retail prices, until decommissioning is complete, as authorized by OPUC (Order #07-015, dtd 1/12/2007 and updated by Order #18-464), offset in Account 407.

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



## Transmission Service and Generation Interconnection Study Costs

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

| Line No. | Description (a) | Costs Incurred During Period (b) | Account Charged (c) | Reimbursements Received During the Period (d) | Account Credited With Reimbursement (e) |
|---|---|---|---|---|---|
| 1 | **Transmission Studies** | | | | |
| 2 | | | | | |
| 3 | | | | | |
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| 18 | | | | | |
| 19 | | | | | |
| 20 | | | | | |
| 21 | **Generation Studies** | | | | |
| 22 | 17-068 | 1,019 | 561.7 | | 456 |
| 23 | 18-071 | 15,120 | 561.7 | | 456 |
| 24 | 19-076 | 12,816 | 561.7 | 5,379 | 456 |
| 25 | 19-080 | 34,635 | 561.7 | 34,635 | 456 |
| 26 | 19-081 | 22,891 | 561.7 | 22,891 | 456 |
| 27 | 20-082 | 8,995 | 561.7 | 8,995 | 456 |
| 28 | 20-083 | 26,444 | 561.7 | 26,444 | 456 |
| 29 | 20-084 | 31,238 | 561.7 | 30,036 | 456 |
| 30 | 20-085 | 281 | 561.7 | 137 | 456 |
| 31 | ASIS-001 | 24,292 | 561.7 | 24,292 | 456 |
| 32 | LPQ0001 | 14,537 | 561.7 | 14,551 | 456 |
| 33 | SRPL-001 | 3,162 | 561.7 | 3,162 | 456 |
| 34 | | | | | |
| 35 | | | | | |
| 36 | | | | | |
| 37 | | | | | |
| 38 | | | | | |
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| 40 | | | | | |

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 | 32,287,318 | 8,622,486 | | | 40,909,804 |
| 2 | Previously Flowed to Customers | 12,246,913 | 3,270,598 | | | 15,517,511 |
| 3 | (Amort. period is based on the lives of the | | | | | |
| 4 | properties, approximately 25 years.) | | | | | |
| 5 | | | | | | |
| 6 | Price Risk Management | 95,030,232 | 516,500,277 | VARIOUS | 487,350,329 | 124,180,180 |
| 7 | | | | | | |
| 8 | Deferred Broker Settlement | | 29,950,614 | VARIOUS | 28,978,575 | 972,039 |
| 9 | | | | | | |
| 10 | Intervenor Funding (original deferral per OPUC | 954,680 | 568,717 | VARIOUS | 940,282 | 583,115 |
| 11 | Order No. 03-388 dtd 7/2/2003) | | | | | |
| 12 | | | | | | |
| 13 | Coyote Springs Major Maintenance Accrual LTSA | 2,546,405 | 2,307,002 | VARIOUS | 1,978,908 | 2,874,499 |
| 14 | (per OPUC GRC 95-1216, dtd 11/20/1995) | | | | | |
| 15 | | | | | | |
| 16 | Residual Deferred Account | 312,049 | 6,567 | 182.3 | 313,418 | 5,198 |
| 17 | (per OPUC Order No. 10-279 dtd 7/23/2010) | | | | | |
| 18 | | | | | | |
| 19 | Glass Insulator Deferral | 5,505,228 | | 571 | 106,333 | 5,398,895 |
| 20 | (per OPUC Order No. 10-478 dtd 12/17/2010; | | | | | |
| 21 | UE 215 First Revenue Requirement Stipulation) | | | | | |
| 22 | Amortization period: 56 years | | | | | |
| 23 | | | | | | |
| 24 | Pension Funding | 212,838,977 | 43,644,096 | 219 | 16,864,727 | 239,618,346 |
| 25 | Postretirement Funding | 31,897 | | 219 | 31,897 | |
| 26 | (Per SFAS No. 158 adopted 12/31/2006; | | | | | |
| 27 | OPUC Order No. 07-051 dtd 2/12/2007) | | | | | |
| 28 | | | | | | |
| 29 | Boardman Decommissioning Balancing | ( 46,738) | 163,829 | VARIOUS | 168,222 | -51,131 |
| 30 | (Per Advice No. 11-07 dtd 05/27/2011) | | | | | |
| 31 | | | | | | |
| 32 | Automated Demand Response Cost Recovery Mechanism | ( 150,658) | 8,826,802 | VARIOUS | 8,417,450 | 258,694 |
| 33 | (Per OPUC Advice No. 17-29, dtd 11/13/17) | | | | | |
| 34 | (Amortization period 1/1/2020-12/31/2020) | | | | | |
| 35 | | | | | | |
| 36 | Demand Response Testbed | 284,945 | 11,073,611 | VARIOUS | 11,358,556 | |
| 37 | (Per OPUC Order No. 19-425, dtd 12/06/2019) | | | | | |
| 38 | (Amortization period 1/1/2020-12/31/2020) | | | | | |
| 39 | | | | | | |
| 40 | CET Deferral (2014-2018 vintages) | 9,123,877 | 1,049,031 | 421/903 | 3,831,482 | 6,341,426 |
| 41 | (amortization per OPUC Order No. 17-511, | | | | | |
| 42 | dtd 12/18/17) | | | | | |
| 43 | (Amortization period 01/01/2018-12/31/2022) | | | | | |
| 44 | TOTAL | 422,858,216 | 789,658,895 | | 685,973,036 | 526,544,075 |

OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets (a) | Balance at Beginning of Current Quarter/Year (b) | Debits (c) | CREDITS Written off During the Quarter/Year Account Charged (d) | CREDITS Written off During the Period Amount (e) | Balance at end of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | Schedule 110 Energy Efficiency | 4,550 | 1,084,590 | VARIOUS | 1,078,680 | 10,460 |
| 3 | (per OPUC Advice No. 10-01) | | | | | |
| 4 | | | | | | |
| 5 | Deferred Cost - Pricing Program | 2,296,459 | 2,579,652 | VARIOUS | 4,616,365 | 259,746 |
| 6 | (Per OPUC Order No. 19-313 dtd 9/26/19, UM 1708) | | | | | |
| 7 | (Amortization period 1/1/2020-12/31/2021) | | | | | |
| 8 | | | | | | |
| 9 | Deferred Cost - DLC Thermostat | 4,426,480 | 4,573,751 | VARIOUS | 8,069,003 | 931,228 |
| 10 | (Per OPUC Order No.19-313 dtd 9/26/19, UM 1708) | | | | | |
| 11 | (Amortization period 1/1/2020-12/31/2021) | | | | | |
| 12 | | | | | | |
| 13 | Gresham Privilege Tax Collection Deferral | 4,799,365 | 607,519 | 407.3 | 1,961,465 | 3,445,419 |
| 14 | (Advice No. 17-05, Schedule 134, dtd 02/24/17) | | | | | |
| 15 | (Amortization period 1/1/2018-12/31/2022) | | | | | |
| 16 | | | | | | |
| 17 | Portland Harbor Environmental | 14,631,343 | 21,170,363 | VARIOUS | 13,484,767 | 22,316,939 |
| 18 | Remediation Deferral | | | | | |
| 19 | (Per OPUC Order No. 17-071, | | | | | |
| 20 | Docket No. UM1789, dtd 03/02/17) | | | | | |
| 21 | | | | | | |
| 22 | Residential Sch123 SNA Deferral-2017 | ( 77,129) | 1,094,146 | 254/456 | 1,017,017 | |
| 23 | (reauthorized Advice No. 16-23, dtd 11/23/2016) | | | | | |
| 24 | | | | | | |
| 25 | Residential Sch123 SNA Deferral-2018 | 4,484,188 | 764,062 | 456 | 5,064,427 | 183,823 |
| 26 | (reauthorized Advice No. 16-23, dtd 11/23/2016 | | | | | |
| 27 | amortization period 1/1/2020-12/31/2020) | | | | | |
| 28 | | | | | | |
| 29 | Lost Revenue Recovery-2017 | 15,392 | 37,703 | 456 | 53,095 | |
| 30 | (Per OPUC Order No. 16-359 dtd 9/26/2016, | | | | | |
| 31 | amortization period 1/1/2019-12/31/2019, | | | | | |
| 32 | per Advice No. 17-24) | | | | | |
| 33 | | | | | | |
| 34 | Non-residential Sch 123 SNA Deferral-2020 | | 15,799,242 | VARIOUS | 15,759,214 | 40,028 |
| 35 | (Reauthorized Advice No. 16-23, dtd 11/23/2016) | | | | | |
| 36 | | | | | | |
| 37 | Residential Sch123 SNA Deferral-2020 | | 9,518,927 | 421/456 | 20,993 | 9,497,934 |
| 38 | (Reauthorized Advice No. 16-23, dtd 11/23/2016) | | | | | |
| 39 | | | | | | |
| 40 | Lost Revenue Recovery-2019 | | 325,100 | | | 325,100 |
| 41 | (Per OPUC Order No. 16-359 dtd 9/26/2016) | | | | | |
| 42 | | | | | | |
| 43 | Interest Rate Swap | 4,583,799 | 26,044 | 428 | 182,308 | 4,427,535 |
| 44 | TOTAL | 422,858,216 | 789,658,895 | | 685,973,036 | 526,544,075 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2020/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 | Interest Rate Hedges for Long Term Debt | | | | | |
| 2 | Amortization period: 30 years | | | | | |
| 3 | | | | | | |
| 4 | Transportation Electrification Prgm | 309,603 | 267,260 | 107 | 6,011 | 570,852 |
| 5 | (Per UM 1811, Order No. 18-124, dtd 4/12/2018) | | | | | |
| 6 | | | | | | |
| 7 | Multifamily Water Heater | 1,290,543 | 7,172,987 | VARIOUS | 7,679,741 | 783,789 |
| 8 | (Per Advice Filing No. 17-06, UM-1827, | | | | | |
| 9 | Order No. 17-224, dtd 6/27/2017) | | | | | |
| 10 | (Amortization period 1/1/2020-12/31/2020) | | | | | |
| 11 | | | | | | |
| 12 | Multnomah County Business Income Tax Balancing | 217,795 | | 242 | 217,795 | |
| 13 | (per Advice 11-27 dtd 10/27/2012) | | | | | |
| 14 | | | | | | |
| 15 | Community Solar | 341,418 | 1,968,505 | VARIOUS | 1,176,897 | 1,133,026 |
| 16 | (Per UM-1977, OPUC Order No. 18-477, | | | | | |
| 17 | dtd 12/19/2018) | | | | | |
| 18 | | | | | | |
| 19 | Photovoltaic Volumetric Incentive Pilot | | 20,748,371 | VARIOUS | 20,748,371 | |
| 20 | (Per OPUC Order No. 10-198 dtd 5/28/2010) | | | | | |
| 21 | (Reauthorized OPUC Order No. 15-185 dtd 6/09/2015) | | | | | |
| 22 | | | | | | |
| 23 | Residential Sch123 SNA Deferral-2019 | 10,785,726 | 15,970,513 | 182.3/456 | 13,393,334 | 13,362,905 |
| 24 | (Reauthorized Advice No. 16-23, dtd 11/23/2016) | | | | | |
| 25 | | | | | | |
| 26 | Non-residential Sch 123 SNA Deferral 2019 | 3,783,559 | 4,748,685 | 182.3/456 | 4,274,571 | 4,257,673 |
| 27 | (reauthorized Advice No. 16-23, dtd 11/23/2016) | | | | | |
| 28 | | | | | | |
| 29 | Residential Battery Energy Storage Pilot | | 17,745 | 920 | 6,140 | 11,605 |
| 30 | (Per UM-2078, Order No. 20-208, dtd 7/6/2020) | | | | | |
| 31 | | | | | | |
| 32 | Wheatridge Renewable Energy Farm | | 1,588,025 | 553 | 4,411 | 1,583,614 |
| 33 | (Per UE-370, Order No. 20-279, dtd 8/26/2020) | | | | | |
| 34 | | | | | | |
| 35 | Emergency Wildfire | | 25,191,476 | 421/593 | 9,731,255 | 15,460,221 |
| 36 | (Per UM-2115, Order No. 20-389, dtd 10/27/2020) | | | | | |
| 37 | | | | | | |
| 38 | COVID-19 | | 18,438,403 | VARIOUS | 8,199,784 | 10,238,619 |
| 39 | (Per UM-2064, Order No. 20-376, dtd 10/27/2020) | | | | | |
| 40 | | | | | | |
| 41 | Oregon Commercial Activity Tax | | 8,868,445 | VARIOUS | 8,887,213 | -18,768 |
| 42 | (Per UM-2037, UE 368, Order No. 20-029, | | | | | |
| 43 | dtd 01/29/2020) | | | | | |
| 44 | TOTAL | 422,858,216 | 789,658,895 | | 685,973,036 | 526,544,075 |

## OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets (a) | Balance at Beginning of Current Quarter/Year (b) | Debits (c) | CREDITS Written off During the Quarter/Year Account Charged (d) | CREDITS Written off During the Period Amount (e) | Balance at end of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | OPUC Fee Deferral | | 1,113,751 | | | 1,113,751 |
| 3 | (Per UM-2046, Order No. 20-411, dtd 11/05/2020) | | | | | |
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| 41 | | | | | | |
| 42 | | | | | | |
| 43 | | | | | | |
| 44 | TOTAL | 422,858,216 | 789,658,895 | | 685,973,036 | 526,544,075 |

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) _ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

**Schedule Page: 232 Line No.: 6 Column: d**
PRM 182.3/254/547/555

**Schedule Page: 232 Line No.: 8 Column: d**
Deferred Broker Settlements 134/182.3/254/547/555

**Schedule Page: 232 Line No.: 10 Column: d**
Intervenors: 182.3/407.3

**Schedule Page: 232 Line No.: 13 Column: d**
Coyote Springs MMA: 182.3/407.3

**Schedule Page: 232 Line No.: 29 Column: d**
Boardman Decomm: 421/431/456

**Schedule Page: 232 Line No.: 32 Column: b**
Beginning balance includes a reclassification of $284,945 to Demand Response Testbed.

**Schedule Page: 232 Line No.: 32 Column: d**
ADR: 143/182.3/232/407.3/421

**Schedule Page: 232 Line No.: 36 Column: b**
Beginning balance includes a reclassification of $284,945 from Automated Demand Response Cost Recovery Mechanism.

**Schedule Page: 232 Line No.: 36 Column: d**
Demand Response Testbed: 182.3/251/407.3/421/431

**Schedule Page: 232.1 Line No.: 2 Column: d**
SCH 110 Energy Efficiency: 254/407.3/431

**Schedule Page: 232.1 Line No.: 5 Column: b**
Beginning balance includes a reclassification of $77,083 from Res. Thermo Direct Install and $2,297,553 from Res. Pricing Program.

**Schedule Page: 232.1 Line No.: 5 Column: d**
182.3/507.3/421.

**Schedule Page: 232.1 Line No.: 9 Column: b**
Beginning balance includes a reclassification of $2,096,121 from Res. Thermo Direct Install.

**Schedule Page: 232.1 Line No.: 9 Column: d**
182.3/407.3.

**Schedule Page: 232.1 Line No.: 17 Column: d**
PHERA: 107/131/182.3/421/923

**Schedule Page: 232.1 Line No.: 34 Column: d**
NonRes SNA 2020: 182.3/254/407.4/421/431/456/904.

**Schedule Page: 232.2 Line No.: 7 Column: b**
Beginning balance includes a reclassification of $270,000 from Res. Water Heater.

**Schedule Page: 232.2 Line No.: 7 Column: d**
182.3/242/407.3

**Schedule Page: 232.2 Line No.: 15 Column: d**
Community Solar: 407.3/417.1/421

**Schedule Page: 232.2 Line No.: 19 Column: d**
FiT: 131/254/407.3/421/431/555

**Schedule Page: 232.2 Line No.: 23 Column: b**
Beginning balance includes a reclassification of $1,175,939 from Residential Sch 123 SNA Deferral-2019 to Non-residential Sch 123 SNA Deferral-2019.

**Schedule Page: 232.2 Line No.: 26 Column: b**
Beginning balance includes a reclassification of $1,175,939 from Residential Sch 123 SNA Deferral-2019 to Non-residential Sch 123 SNA Deferral-2019.

**Schedule Page: 232.2 Line No.: 38 Column: d**
COVID-19: 182.3/421/431/904

**Schedule Page: 232.2 Line No.: 41 Column: d**
OCAT: 182.3/254/407.4/431/904

## 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 | 354,221 | 475,718 | Various | 537,675 | 292,264 |
| 3 | | | | | | |
| 4 | Net Co-owner / Trust Contributi | 316,103 | 80,197,317 | Various | 80,192,838 | 320,582 |
| 5 | | | | | | |
| 6 | Deferred Revolving Credit | 1,276,225 | | 431 | 326,109 | 950,116 |
| 7 | Agreement Fees | | | | | |
| 8 | amort. through November 2023 | | | | | |
| 9 | | | | | | |
| 10 | Dispatchable Generation | 10,802,749 | 571,047 | 903 | 1,806,129 | 9,567,667 |
| 11 | various amort. periods from | | | | | |
| 12 | 2009 and extending through 2028 | | | | | |
| 13 | | | | | | |
| 14 | Utility Property Sales- | 43,949 | 32,329 | | | 76,278 |
| 15 | Selling Expenses | | | | | |
| 16 | | | | | | |
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| 47 | Misc. Work in Progress | 687,223 | | | | 34,304 |
| 48 | Deferred Regulatory Comm. Expenses (See pages 350 - 351) | | | | | |
| 49 | TOTAL | 13,480,470 | | | | 11,241,211 |

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 | 311,034,575 | 319,689,145 |
| 3 | Regulatory Liabilities | 22,112,547 | 21,459,037 |
| 4 | Employee Benefits | 119,856,422 | 136,517,004 |
| 5 | Price Risk Management | 36,064,583 | 41,506,877 |
| 6 | Tax Credits & NOL's | 64,215,361 | 77,041,984 |
| 7 | Other | 5,704,912 | 12,016,102 |
| 8 | TOTAL Electric (Enter Total of lines 2 thru 7) | 558,988,400 | 608,230,149 |
| 9 | Gas | | |
| 10 | | | |
| 11 | | | |
| 12 | | | |
| 13 | | | |
| 14 | | | |
| 15 | Other | | |
| 16 | TOTAL Gas (Enter Total of lines 10 thru 15 | | |
| 17 | Other (Specify) | 4,340,861 | 9,409,220 |
| 18 | TOTAL (Acct 190) (Total of lines 8, 16 and 17) | 563,329,261 | 617,639,369 |

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<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

***Schedule Page: 234 Line No.: 7 Column: b***

Line 7 - Other

| | Ending Bal 12/31/2019 | Ending Bal 12/31/2020 |
|---|---|---|
| Bad Debt Expense | $1,231,143 | $4,301,616 |
| Deferred Revenue | 2,062,276 | 1,362,280 |
| Nuclear Decommissioning Trust | 7,632,027 | 8,492,158 |
| Renewable Energy Development | 3,761,140 | 3,653,395 |
| Miscellaneous | -8,981,674 | -5,793,347 |
| Total Line 7 - Other | $5,704,912 | $12,016,102 |

***Schedule Page: 234 Line No.: 17 Column: b***

Line 17 - Other Non-Utility

| | Ending Bal 12/31/2019 | Ending Bal 12/31/2020 |
|---|---|---|
| Property Related | $4,265,935 | $9,409,495 |
| Employee Benefits | 74,926 | -275 |
| Total Line 17 - Other Non-Utility | $4,340,861 | $9,409,220 |

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 Common Stock | 160,000,000 | | |
| 5 | | | | |
| 6 | Account 204: | | | |
| 7 | No par Value Cumulative Preferred | 30,000,000 | | |
| 8 | | | | |
| 9 | Total Preferred Stock | 30,000,000 | | |
| 10 | | | | |
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

| OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent) | | HELD BY RESPONDENT | | | | Line No. |
|---|---|---|---|---|---|---|
| | | AS REACQUIRED STOCK (Account 217) | | IN SINKING AND OTHER FUNDS | | |
| Shares (e) | Amount (f) | Shares (g) | Cost (h) | Shares (i) | Amount (j) | |
| | | | | | | 1 |
| 89,537,331 | 1,234,951,127 | | | | | 2 |
| | | | | | | 3 |
| 89,537,331 | 1,234,951,127 | | | | | 4 |
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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 | | |
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| 38 | | |
| 39 | | |
| 40 | TOTAL | 18,838,837 |

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

***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.

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 | | |
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| 16 | | |
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| 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 | 6.875% Series VI Due 8/1/2033 | 50,000,000 | 519,257 |
| 5 | | | 437,500 D |
| 6 | 6.26% Series Due 5/1/2031 | 100,000,000 | 723,856 |
| 7 | 6.31% Series Due 5/1/2036 | 175,000,000 | 1,270,565 |
| 8 | 5.80% Series Due 6/1/2039 | 170,000,000 | 1,460,968 |
| 9 | 5.81% Series Due 10/1/2037 | 130,000,000 | 1,109,574 |
| 10 | | | 517,518 D |
| 11 | 5.43% Series Due 5/3/2040 - Order No. 09-245 06/22/2009 | 150,000,000 | 1,034,284 |
| 12 | 4.47% Series Due 6/15/2044 - Order No. 13-098 03/26/2013 | 150,000,000 | 1,113,047 |
| 13 | 4.47% Series Due 8/14/2043 - Order No. 13-098 03/26/2013 | 75,000,000 | 558,740 |
| 14 | 4.84% Series Due 12/15/2048 - Order No. 13-098 03/26/2013 | 50,000,000 | 311,154 |
| 15 | 4.74% Series Due 11/15/2042 - Order No. 13-098 03/26/2013 | 105,000,000 | 652,029 |
| 16 | 4.39% Series Due 8/15/2045 - Order No. 14-145 04/29/2014 | 100,000,000 | 645,383 |
| 17 | 4.44% Series Due 10/15/2046 - Order No. 14-145 04/29/2014 | 100,000,000 | 625,030 |
| 18 | 3.51% Series Due 11/15/2024 - Order No. 14-145 04/29/2014 | 80,000,000 | 501,502 |
| 19 | 3.55% Series Due 1/15/2030 - Order No. 14-399 11/12/2014 | 75,000,000 | 325,296 |
| 20 | 3.50% Series Due 5/15/2035 - Order No. 14-399 11/12/2014 | 70,000,000 | 305,128 |
| 21 | 2.51% Series Due 1/6/2021 - Order No. 14-399 11/12/2014 | 140,000,000 | 592,932 |
| 22 | 3.98% Series Due 11/21/2047 - Order No. 16-152 04/21/2016 | 150,000,000 | -99,510 |
| 23 | 3.98% Series Due 8/3/2048 - Order No. 16-152 04/21/2016 | 75,000,000 | -44,757 |
| 24 | 4.47% SERIES DUE 12-11-2048 Order No. 16-152 04/21/2016 | 75,000,000 | 336,938 |
| 25 | 4.30% Series Due 4/11/2049 Order No. 18-453 12/04/2018 | 200,000,000 | 860,461 |
| 26 | 3.34% Series Due 10/15/2049 Order No. 18-453 12/04/2018 | 110,000,000 | 477,767 |
| 27 | 3.34% Series Due 1/15/2050 Order No. 18-453 12/04/2018 | 160,000,000 | 694,934 |
| 28 | 3.15% Series Due 4/1/2030 Order No. 18-454 12/4/2018 | 200,000,000 | 862,049 |
| 29 | 1.84% Series Due 12/10/2027 Order No. 20-169 5/22/2020 | 160,000,000 | 645,816 |
| 30 | 2.32% Series Due 12/10/2032 Order No. 20-169 5/22/2020 | 70,000,000 | 278,000 |
| 31 | | | |
| 32 | | | |
| 33 | TOTAL | 3,156,600,000 | 18,177,501 |

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

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

| Line No. | Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a) | Principal Amount Of Debt issued (b) | Total expense, Premium or Discount (c) |
|---|---|---|---|
| 1 | Pollution Control Bonds (Guaranteed by Company) - | | |
| 2 | City of Forsyth, MT Series 1998A 5% Due 5/1/2033 | 97,800,000 | 2,615,167 |
| 3 | City of Forsyth, MT Series 2.125% Due 05/01/2033 Order 09-099 3/26/2009 | 97,800,000 | 528,702 |
| 4 | | | -1,956,000 P |
| 5 | City of Forsyth, MT Series 2.375% Due 05/01/2033 Order 09-099 3/26/2009 | 21,000,000 | 97,594 |
| 6 | SUBTOTAL ACCOUNT 221 | 3,156,600,000 | 18,177,501 |
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| 31 | | | |
| 32 | | | |
| 33 | TOTAL | 3,156,600,000 | 18,177,501 |

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 | 08/01/2033 | 08/01/2003 | 08/01/2033 | 50,000,000 | 3,437,500 | 4 |
| | | | | | | 5 |
| 05/26/2006 | 05/01/2031 | 05/26/2006 | 05/01/2031 | 100,000,000 | 6,260,000 | 6 |
| 05/26/2006 | 05/01/2036 | 05/26/2006 | 05/01/2036 | 175,000,000 | 11,042,500 | 7 |
| 05/16/2007 | 06/01/2039 | 05/16/2007 | 06/01/2039 | 170,000,000 | 9,860,000 | 8 |
| 09/19/2007 | 10/01/2037 | 09/19/2007 | 10/01/2037 | 130,000,000 | 7,553,000 | 9 |
| | | | | | | 10 |
| 11/30/2009 | 05/03/2040 | 11/30/2009 | 05/03/2040 | 150,000,000 | 8,145,000 | 11 |
| 6/27/2013 | 06/15/2044 | 6/27/2013 | 06/15/2044 | 150,000,000 | 6,705,000 | 12 |
| 8/29/2013 | 8/14/2043 | 8/29/2013 | 8/14/2043 | 75,000,000 | 3,352,500 | 13 |
| 12/16/2013 | 12/15/2048 | 12/16/2013 | 12/15/2048 | 50,000,000 | 2,420,000 | 14 |
| 11/15/2013 | 11/15/2042 | 11/15/2013 | 11/15/2042 | 105,000,000 | 4,977,000 | 15 |
| 8/15/2014 | 8/15/2045 | 8/15/2014 | 8/15/2045 | 100,000,000 | 4,390,000 | 16 |
| 10/15/2014 | 10/15/2046 | 10/15/2014 | 10/15/2046 | 100,000,000 | 4,440,000 | 17 |
| 11/17/2014 | 11/15/2024 | 11/17/2014 | 11/15/2024 | 80,000,000 | 2,808,000 | 18 |
| 1/15/2015 | 1/15/2030 | 1/15/2015 | 1/15/2030 | 75,000,000 | 2,662,500 | 19 |
| 5/15/2015 | 5/15/2035 | 5/15/2015 | 5/15/2035 | 70,000,000 | 2,450,000 | 20 |
| 1/6/2016 | 1/6/2021 | 1/6/2016 | 1/6/2021 | 140,000,000 | 3,514,000 | 21 |
| 11/21/2017 | 11/21/2047 | 11/21/2017 | 11/21/2047 | 150,000,000 | 5,970,000 | 22 |
| 8/3/2017 | 8/3/2048 | 8/3/2017 | 8/3/2048 | 75,000,000 | 2,985,000 | 23 |
| 12/11/2018 | 12/11/2048 | 12/11/2018 | 12/11/2048 | 75,000,000 | 3,352,500 | 24 |
| 4/19/2019 | 4/11/2049 | 12/11/2019 | 12/11/2049 | 200,000,000 | 8,600,000 | 25 |
| 10/15/2019 | 10/15/2049 | 10/15/2019 | 10/15/2049 | 110,000,000 | 3,674,000 | 26 |
| 11/15/2019 | 1/15/2050 | 11/15/2019 | 1/15/2050 | 160,000,000 | 5,344,000 | 27 |
| 4/27/2020 | 4/1/2030 | 4/27/2020 | 4/1/2030 | 200,000,000 | 4,270,000 | 28 |
| 12/10/2020 | 12/10/2027 | 12/10/2020 | 12/10/2027 | 160,000,000 | 171,733 | 29 |
| 12/10/2020 | 12/10/2032 | 12/10/2020 | 12/10/2032 | 70,000,000 | 94,733 | 30 |
| | | | | | | 31 |
| | | | | | | 32 |
| | | | | 3,058,800,000 | 123,508,651 | 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<br>(2) [ ] A Resubmission | // | End of 2020/Q4 |



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

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

| Nominal Date of Issue (d) | Date of Maturity (e) | AMORTIZATION PERIOD Date From (f) | AMORTIZATION PERIOD Date To (g) | Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h) | Interest for Year Amount (i) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| 05/28/1998 | 05/01/2033 | 05/28/1998 | 05/01/2033 | | 950,833 | 2 |
| 03/11/2020 | 05/01/2033 | 03/11/2020 | 05/01/2033 | 97,800,000 | 1,809,980 | 3 |
| | | | | | | 4 |
| 03/11/2020 | 05/01/2033 | 03/11/2020 | 05/01/2033 | 21,000,000 | 406,872 | 5 |
| | | | | 3,058,800,000 | 123,508,651 | 6 |
| | | | | | | 7 |
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| | | | | | | 32 |
| | | | | 3,058,800,000 | 123,508,651 | 33 |

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

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

| Line No. | Particulars (Details) (a) | Amount (b) |
|---|---|---|
| 1 | Net Income for the Year (Page 117) | 154,620,730 |
| 2 | | |
| 3 | | |
| 4 | Taxable Income Not Reported on Books | |
| 5 | Depreciation, Depletion & Amortization | 114,687,622 |
| 6 | | |
| 7 | | |
| 8 | | |
| 9 | Deductions Recorded on Books Not Deducted for Return | |
| 10 | Price Risk Management and Mark-to-Market | 12,267,046 |
| 11 | Regulatory Credits | -2,696,044 |
| 12 | Other (See Footnote) | 77,914,616 |
| 13 | | |
| 14 | Income Recorded on Books Not Included in Return | |
| 15 | Depreciation, Depletion & Amortization | -23,755,734 |
| 16 | Regulatory Debits | -90,830,152 |
| 17 | Other (See Footnote) | -7,123,664 |
| 18 | | |
| 19 | Deductions on Return Not Charged Against Book Income | |
| 20 | Depreciation, Depletion & Amortization | -96,184,396 |
| 21 | State & Local Tax Deduction | -17,543,049 |
| 22 | Other (See Footnote) | -596,079 |
| 23 | | |
| 24 | | |
| 25 | | |
| 26 | | |
| 27 | Federal Tax Net Income | 120,760,896 |
| 28 | Show Computation of Tax: | |
| 29 | Normal Federal Current Provision Benefit @ 21% | 25,359,788 |
| 30 | Federal Credit Tax | -19,067,709 |
| 31 | RTA Federal Tax Adjustment | 56,789 |
| 32 | Other Items Affecting Tax | -650,302 |
| 33 | Total Federal Income Tax - PGE | 5,698,567 |
| 34 | | |
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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<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

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

**Line 12 - Deductions Recorded on Books Not Deducted for Return**

| | |
|---|---|
| Qualified NDT | 3,127,749 |
| Meals & Entertainment | 230,313 |
| Political Activity | 1,219,135 |
| Bad Debts | 11,165,359 |
| Fines and Penalties | 132,974 |
| Employee Benefits | 64,630,606 |
| Federal Tax Expense | (16,541,171) |
| Orion Contingent Royalty Payments | (915,180) |
| Tax Finance Lease | 2,456,483 |
| Unamortized loss on reacquired debt | 1,290,092 |
| State & Local Tax Expense | 15,702,693 |
| Deferred Revenue | (2,386,347) |
| Miscellaneous | (2,198,090) |
| **Total Other** | **77,914,616** |

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

**Line 17 - Income Recorded on Books Not Included in Return**

| | |
|---|---|
| Key Man Life Insurance | (4,267,563) |
| OCI | (2,054,875) |
| Miscellaneous | (801,226) |
| **Total Other** | **(7,123,664)** |

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

**Line 22 - Deductions on Return Not Charged Against Book Income**

| | |
|---|---|
| Dividend Received Deduction | (33,000) |
| Prepaid | (947,670) |
| Renewable Energy Initiatives | (45,696) |
| Property Tax | (4,065,992) |
| Accumulated ARO Sullivan | 4,299,949 |
| Miscellaneous | 196,330 |
| **Total Other** | |

| Name of Respondent | This Report is: | Date of Report | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | (Mo, Da, Yr)<br>/ / | 2020/Q4 |

FOOTNOTE DATA

**(596,079)**

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2020/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 | 212,665 | | 881,009 | 874,939 | |
| 3 | Income Tax | | 3,635,818 | 5,698,759 | 3,650,000 | |
| 4 | Foreign Insurance Excise Tax | | | | | |
| 5 | FICA (Employer Share) | 3,589,927 | | 24,553,447 | 13,625,004 | 1 |
| 6 | Unemployment | 72,425 | | 66,763 | 137,293 | |
| 7 | Power License | 282,135 | -34,115 | 2,109,735 | 1,908,831 | |
| 8 | Superfund Tax | | | | | |
| 9 | SUBTOTAL Federal | 4,157,152 | 3,601,703 | 33,309,713 | 20,196,067 | 1 |
| 10 | State of Montana: | | | | | |
| 11 | Income Tax | | -311,187 | 214,130 | 100,000 | |
| 12 | Electric Energy Producers | 211,170 | | 761,901 | 649,148 | |
| 13 | Property Taxes | 3,894,921 | | 7,959,294 | 7,927,096 | |
| 14 | SUBTOTAL Montana | 4,106,091 | -311,187 | 8,935,325 | 8,676,244 | |
| 15 | State of Oregon: | | | | | |
| 16 | Corp Excise Tax and CAT | 243,008 | 7,929,519 | 15,804,465 | 11,024,261 | |
| 17 | Property Taxes | | 31,686,422 | 69,058,223 | 73,054,662 | -1,614,737 |
| 18 | City Taxes & Licenses | 3,504,987 | | 46,038,477 | 45,858,355 | 1 |
| 19 | Public Utility Comm Fees | | -78,530 | 7,439,408 | 7,517,938 | |
| 20 | Department of Energy | | 962,906 | 2,076,210 | 2,226,607 | -1 |
| 21 | Department of Enviro Quality | 489,705 | | 855,696 | 678,027 | |
| 22 | Unemployment | 220,011 | | 1,428,468 | 1,618,459 | -1 |
| 23 | Water Power Fee | | 630,768 | 632,183 | | |
| 24 | Transportation Tax | 524,680 | | 2,120,589 | 2,094,787 | -1 |
| 25 | Workers Comp Assessment | -156,714 | | 403,597 | 246,884 | 1 |
| 26 | County & City Income Tax | | 692,035 | 344,203 | 335,000 | |
| 27 | SUBTOTAL Oregon | 4,825,677 | 41,823,120 | 146,201,519 | 144,654,980 | -1,614,738 |
| 28 | State of Washington: | | | | | |
| 29 | Property Taxes | 2,383,257 | | 2,220,400 | 2,339,540 | |
| 30 | Sales Tax | | | | | |
| 31 | SUBTOTAL WASHINGTON | 2,383,257 | | 2,220,400 | 2,339,540 | |
| 32 | State of Utah | | | | | |
| 33 | Income Tax | | | | | |
| 34 | SUBTOTAL Utah | | | | | |
| 35 | State of California: | | | | | |
| 36 | Corporate Franchise Tax | | -1,065,125 | 359,174 | 150,000 | |
| 37 | SUBTOTAL California | | -1,065,125 | 359,174 | 150,000 | |
| 38 | Canada | | | | | |
| 39 | Goods & Services Tax | | | | | |
| 40 | SUBTOTAL Canada | | | | | |
| 41 | TOTAL | 15,472,177 | 44,048,511 | 191,026,131 | 176,016,831 | -1,614,737 |

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 |
| 218,735 | | | | | 881,009 | 2 |
| | 1,587,059 | 7,733,048 | | | -2,034,289 | 3 |
| | | | | | | 4 |
| 14,518,371 | | 12,511,510 | | | 12,041,937 | 5 |
| 1,895 | | 34,025 | | | 32,738 | 6 |
| 262,130 | -255,024 | | | | 2,109,735 | 7 |
| | | | | | | 8 |
| 15,001,131 | 1,332,035 | 20,278,583 | | | 13,031,130 | 9 |
| | | | | | | 10 |
| | -425,317 | 234,952 | | | -20,821 | 11 |
| 323,923 | | 444,751 | | | 317,150 | 12 |
| 3,927,119 | | 5,954,439 | | | 2,004,855 | 13 |
| 4,251,042 | -425,317 | 6,634,142 | | | 2,301,184 | 14 |
| | | | | | | 15 |
| 243,008 | 3,149,315 | 16,582,141 | | | -777,677 | 16 |
| -2,358 | 37,295,240 | 65,155,885 | | | 3,902,338 | 17 |
| 3,685,110 | | 46,038,477 | | | | 18 |
| | | | | | 7,439,408 | 19 |
| | 1,113,304 | 2,076,210 | | | | 20 |
| 667,374 | | | | | 855,696 | 21 |
| 30,019 | | 725,440 | | | 703,028 | 22 |
| | -1,415 | | | | 632,183 | 23 |
| 550,481 | | 1,076,930 | | | 1,043,659 | 24 |
| | | 204,965 | | | 198,632 | 25 |
| | 682,832 | 398,290 | | | -54,087 | 26 |
| 5,173,634 | 42,239,276 | 132,258,338 | | | 13,943,180 | 27 |
| | | | | | | 28 |
| 2,264,117 | | 2,220,400 | | | | 29 |
| | | | | | | 30 |
| 2,264,117 | | 2,220,400 | | | | 31 |
| | | | | | | 32 |
| | | | | | | 33 |
| | | | | | | 34 |
| | | | | | | 35 |
| | -1,274,299 | 371,812 | | | -12,638 | 36 |
| | -1,274,299 | 371,812 | | | -12,638 | 37 |
| | | | | | | 38 |
| | | | | | | 39 |
| | | | | | | 40 |
| 26,689,924 | 41,871,695 | 161,763,275 | | | 29,262,856 | 41 |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

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

**Line 17 -Adjustments**

| | |
|---|---|
| Property Tax Bill to Others | (1,628,834) |
| Property Tax BTO - Write Off | 14,097 |
| **Total** | **(1,614,737)** |

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

## ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

| Line No. | Account Subdivisions (a) | Balance at Beginning of Year (b) | Deferred for Year | | Allocations to Current Year's Income | | Adjustments (g) |
|---|---|---|---|---|---|---|---|
| | | | Account No. (c) | Amount (d) | Account No. (e) | Amount (f) | |
| 1 | Electric Utility | | | | | | |
| 2 | 3% | | | | | | |
| 3 | 4% | | | | | | |
| 4 | 7% | | | | | | |
| 5 | 10% | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | TOTAL | | | | | | |
| 9 | Other (List separately and show 3%, 4%, 7%, 10% and TOTAL) | | | | | | |
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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 |
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## 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 | | | | 160,000 | 160,000 |
| 2 | | | | | | |
| 3 | Deferred Liability for Transferred | 555,126 | 421 | 19,609 | | 535,517 |
| 4 | Non-Qualified Plan Benefits | | | | | |
| 5 | | | | | | |
| 6 | Reserve for Environmental | 4,000,000 | | | | 4,000,000 |
| 7 | Remediation Costs | | | | | |
| 8 | | | | | | |
| 9 | Deferral of Precedent Transmission | 1,455,442 | 565 | 2,045,339 | 589,897 | |
| 10 | Service Agreement with DET, EDF | | | | | |
| 11 | | | | | | |
| 12 | Clean Fuels Program | 8,841,842 | 232,926 | 4,622,756 | 6,448,793 | 10,667,879 |
| 13 | OPUC 17-250 and 17-512 | | | | | |
| 14 | | | | | | |
| 15 | Price Risk Management | -295,008 | 555 | 657,390 | 952,398 | |
| 16 | | | | | | |
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| 46 | | | | | | |
| 47 | TOTAL | 14,557,402 | | 7,345,094 | 8,151,088 | 15,363,396 |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

***Schedule Page: 269 Line No.: 12 Column: d***

The debits are expenses associated with the program, including administrative costs and other payments related to the initiatives the program supports.

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<br>(a) | Balance at Beginning of Year<br>(b) | CHANGES DURING YEAR<br>Amounts Debited to Account 410.1<br>(c) | CHANGES DURING YEAR<br>Amounts Credited to Account 411.1<br>(d) |
|---|---|---|---|---|
| 1 | Accelerated Amortization (Account 281) | | | |
| 2 | Electric | | | |
| 3 | Defense Facilities | | | |
| 4 | Pollution Control Facilities | | | |
| 5 | Other (provide details in footnote): | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | TOTAL Electric (Enter Total of lines 3 thru 7) | | | |
| 9 | Gas | | | |
| 10 | Defense Facilities | | | |
| 11 | Pollution Control Facilities | | | |
| 12 | Other (provide details in footnote): | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | TOTAL Gas (Enter Total of lines 10 thru 14) | | | |
| 16 | | | | |
| 17 | TOTAL (Acct 281) (Total of 8, 15 and 16) | | | |
| 18 | Classification of TOTAL | | | |
| 19 | Federal Income Tax | | | |
| 20 | State Income Tax | | | |
| 21 | Local Income Tax | | | |

NOTES

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

3. Use footnotes as required.

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

NOTES (Continued)

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) | Amounts Credited to Account 411.1 (d) |
|---|---|---|---|---|
| 1 | Account 282 | | | |
| 2 | Electric | 800,256,070 | 74,836,300 | 64,552,910 |
| 3 | Gas | | | |
| 4 | | | | |
| 5 | TOTAL (Enter Total of lines 2 thru 4) | 800,256,070 | 74,836,300 | 64,552,910 |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | TOTAL Account 282 (Enter Total of lines 5 thru | 800,256,070 | 74,836,300 | 64,552,910 |
| 10 | Classification of TOTAL | | | |
| 11 | Federal Income Tax | 642,494,895 | 50,765,591 | 45,581,121 |
| 12 | State Income Tax | 147,727,378 | 22,561,243 | 17,784,010 |
| 13 | Local Income Tax | 10,033,797 | 1,509,466 | 1,187,779 |

NOTES

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

3. Use footnotes as required.

| CHANGES DURING YEAR | | ADJUSTMENTS | | | | | |
|---|---|---|---|---|---|---|---|
| Amounts Debited to Account 410.2 | Amounts Credited to Account 411.2 | Debits | | Credits | | Balance at End of Year | Line No. |
| | | Account Credited | Amount | Account Debited | Amount | | |
| (e) | (f) | (g) | (h) | (i) | (j) | (k) | |
| | | | | | | | 1 |
| | | 182.3 | 11,835,673 | 254 | 20,458,160 | 819,161,947 | 2 |
| | | | | | | | 3 |
| | | | | | | | 4 |
| | | | 11,835,673 | | 20,458,160 | 819,161,947 | 5 |
| | | | | | | | 6 |
| | | | | | | | 7 |
| | | | | | | | 8 |
| | | | 11,835,673 | | 20,458,160 | 819,161,947 | 9 |
| | | | | | | | 10 |
| | | | 8,709,883 | | 14,924,635 | 653,894,117 | 11 |
| | | | 2,937,900 | | 5,192,269 | 154,758,980 | 12 |
| | | | 187,890 | | 341,256 | 10,508,850 | 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 | 12,246,848 | | |
| 4 | Price Risk Management | 10,335,254 | 14,202,728 | 12,133,871 |
| 5 | Regulatory Assets | 103,582,503 | 62,823,042 | 37,872,328 |
| 6 | Regulatory Liabilities | | | |
| 7 | Other | 14,282,925 | 1,606,313 | 820,584 |
| 8 | | | | |
| 9 | TOTAL Electric (Total of lines 3 thru 8) | 140,447,530 | 78,632,083 | 50,826,783 |
| 10 | Gas | | | |
| 11 | | | | |
| 12 | | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | | | | |
| 16 | | | | |
| 17 | TOTAL Gas (Total of lines 11 thru 16) | | | |
| 18 | Other | 882,642 | | |
| 19 | TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18) | 141,330,172 | 78,632,083 | 50,826,783 |
| 20 | Classification of TOTAL | | | |
| 21 | Federal Income Tax | 99,034,001 | 55,105,802 | 35,619,693 |
| 22 | State Income Tax | 39,651,999 | 22,055,452 | 14,256,365 |
| 23 | Local Income Tax | 2,644,172 | 1,470,829 | 950,725 |

NOTES

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

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

| CHANGES DURING YEAR | | ADJUSTMENTS | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Debits | | Credits | | | | |
| Amounts Debited to Account 410.2 (e) | Amounts Credited to Account 411.2 (f) | Account Credited (g) | Amount (h) | Account Debited (i) | Amount (j) | Balance at End of Year (k) | Line No. |
| | | | | | | | 1 |
| | | | | | | | 2 |
| | | 254 | 4,346,390 | 182.3 | 7,617,012 | 15,517,470 | 3 |
| | | | | | | 12,404,111 | 4 |
| | | | | | | 128,533,217 | 5 |
| | | | | | | | 6 |
| | | | | | | 15,068,654 | 7 |
| | | | | | | | 8 |
| | | | 4,346,390 | | 7,617,012 | 171,523,452 | 9 |
| | | | | | | | 10 |
| | | | | | | | 11 |
| | | | | | | | 12 |
| | | | | | | | 13 |
| | | | | | | | 14 |
| | | | | | | | 15 |
| | | | | | | | 16 |
| | | | | | | | 17 |
| 1,040,134 | 128,886 | 254 | 33 | 182.3 | 9 | 1,793,866 | 18 |
| 1,040,134 | 128,886 | | 4,346,423 | | 7,617,021 | 173,317,318 | 19 |
| | | | | | | | 20 |
| 729,234 | 90,480 | | 3,234,964 | | 5,527,017 | 121,450,917 | 21 |
| 291,468 | 36,008 | | 1,042,894 | | 1,960,262 | 48,623,914 | 22 |
| 19,432 | 2,398 | | 68,565 | | 129,742 | 3,242,487 | 23 |

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<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

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

| | Beginning Balance | Ending Balance |
|---|---|---|
| ASC 715 Pension & Post Retirement | 58,539,486 | 65,895,041 |
| ASC 980 Mark-to-Market | 26,133,312 | 34,149,547 |
| Miscellaneous | 14,075,100 | 7,217,119 |
| Decoupling | (231,530) | 7,118,420 |
| CET Deferral | 2,331,247 | 1,504,124 |
| Feed in Tariff (FIT) | (14,225) | (31,284) |
| Portland Harbor (PHERA) | 2,749,113 | 5,715,712 |
| Covid-19 | - | 2,777,977 |
| Wildfire | - | 4,186,561 |
| **Subtotal Regulatory Assets** | **103,582,503** | **128,533,217** |

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

| | Beginning Balance | Ending Balance |
|---|---|---|
| Prepaid Property Tax | 8,285,585 | 9,426,089 |
| Unamortized Loss on Reacquired Debt | 5,997,340 | 5,642,565 |
| **Subtotal Other** | **14,282,925** | **15,068,654** |

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

| | Beginning Balance | Ending Balance |
|---|---|---|
| Other | 419,312 | 1,075,812 |
| Trust Owned Life Insurance | 463,330 | 718,054 |
| **Other** | **882,642** | **1,793,866** |

OTHER REGULATORY LIABILITIES (Account 254)

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

| Line No. | Description and Purpose of Other Regulatory Liabilities (a) | Balance at Begining of Current Quarter/Year (b) | DEBITS Account Credited (c) | DEBITS Amount (d) | Credits (e) | Balance at End of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | Excess Deferred Income Taxes | 304,215,185 | 190 | 12,162,046 | 3,278,370 | 295,331,509 |
| 2 | | | | | | |
| 3 | Gain on Asset Sales | 1,866,501 | | | 54,018 | 1,920,519 |
| 4 | (Per OPUC Order No. 01-777 dtd 8/31/2001) | | | | | |
| 5 | | | | | | |
| 6 | Boardman Severance | 9,017,932 | 456 | 4,978,961 | 2,635,332 | 6,674,303 |
| 7 | Advice No.14-18, dtd 11/3/2014 | | | | | |
| 8 | | | | | | |
| 9 | Asset Retirement Obligations: | 53,681,112 | VARIOUS | 41,472,216 | 24,626,647 | 36,835,543 |
| 10 | Balancing Account | | | | | |
| 11 | | | | | | |
| 12 | Carty Major Maintenance Deferral | 587,055 | 456 | 2,553,070 | 3,201,412 | 1,235,397 |
| 13 | (Per OPUC Order 15-356 UE-294 | | | | | |
| 14 | dtd 11/3/15) | | | | | |
| 15 | | | | | | |
| 16 | Colstrip Major Maintenance Deferral | 5,376,030 | 254/456 | 3,328,603 | 3,199,452 | 5,246,879 |
| 17 | (Per OPUC UE-319, Order No. 17-511, | | | | | |
| 18 | dtd 12/18/17) | | | | | |
| 19 | | | | | | |
| 20 | Port Westward 1 Major Maint Deferral | 469,146 | 456 | 2,099,699 | 3,864,524 | 2,233,971 |
| 21 | (Per OPUC UE 262, Order No. 13-459, | | | | | |
| 22 | dtd 12/9/2013) | | | | | |
| 23 | | | | | | |
| 24 | Port Westward 2 Major Maintenance Deferral | 1,985,112 | | | 968,678 | 2,953,790 |
| 25 | (Per OPUC 2015 GRC Docket UE-283, | | | | | |
| 26 | OPUC Order No.14-422, dtd 12/4/2014) | | | | | |
| 27 | | | | | | |
| 28 | Zero Interest Program Loan Repayments | 3,363,113 | 407/431/447 | 1,534,256 | 277,908 | 2,106,765 |
| 29 | (Per Advice No. 05-19 dtd 12/20/2005) | | | | | |
| 30 | | | | | | |
| 31 | Schedule 110 Energy Efficiency - Balancing Accout | 50,389 | 182.3 | 50,389 | | |
| 32 | (Per Advice No. 07-25 dtd 5/20/2008) | | | | | |
| 33 | | | | | | |
| 34 | Sunway 3 Investment Deferral | 477,430 | 407 | 45,480 | | 431,950 |
| 35 | (Per UM 1480 dtd 4/01/2010; | | | | | |
| 36 | (Amortization over 20 years commencing 2010) | | | | | |
| 37 | | | | | | |
| 38 | Trojan Decommissioning Deferral | 3,293,245 | 407 | 148,448 | 3,743,629 | 6,888,426 |
| 39 | (Per OPUC UE-319, Order No.17-511, | | | | | |
| 40 | dtd 12/18/2017) | | | | | |
| 41 | TOTAL | 408,556,713 | | 151,854,371 | 164,712,767 | 421,415,109 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/16/2021 | End of 2020/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 | (Amortization period 1/1/2019-12/31/2019) | | | | | |
| 2 | | | | | | |
| 3 | PRC Acquisition | 3,601,039 | | | 79,501 | 3,680,540 |
| 4 | (Per OPUC UE-283 Final GRC Order No.14-422, | | | | | |
| 5 | dtd 12/04/2014, Second Partial | | | | | |
| 6 | Stipulation dtd 9/2/2014) | | | | | |
| 7 | | | | | | |
| 8 | Deferred Broker Settlement | 105,850 | 182.3 | 4,827,070 | 4,721,220 | |
| 9 | | | | | | |
| 10 | Photovoltaic Volumetric Incentive Pilot | 2,900,321 | 182.3 | 16,311,858 | 17,955,652 | 4,544,115 |
| 11 | (Per OPUC Order 10-198 dtd 5/28/2010 | | | | | |
| 12 | reauthorized OPUC Order 15-185 | | | | | |
| 13 | dtd 6/09/2015) | | | | | |
| 14 | | | | | | |
| 15 | Portland Harbor Enviornmental Deferral | ( 2,766) | | | | -2,766 |
| 16 | (Per OPUC Order No. 17-071, UM-1789 | | | | | |
| 17 | dtd 03/02/17) | | | | | |
| 18 | | | | | | |
| 19 | Price Risk Management | 1,469,031 | 182.3 | 47,524,699 | 64,407,602 | 18,351,934 |
| 20 | | | | | | |
| 21 | Monet NVPC QF Deferral-2019 | 1,156,116 | 555 | 138,896 | 2,386,433 | 3,403,653 |
| 22 | (Per UE-335 NVPC Stipulation, | | | | | |
| 23 | OPUC Order No. 18-405) | | | | | |
| 24 | | | | | | |
| 25 | Research & Development Tax Credits | 4,733,455 | 190/923 | 13,793 | 738,395 | 5,458,057 |
| 26 | (Per UM-1991, OPUC Order No. 18-464 | | | | | |
| 27 | dtd 12/14/2018) | | | | | |
| 28 | | | | | | |
| 29 | Postretirement Plans | 8,385,769 | 182.3/219 | 5,987,869 | 877,473 | 3,275,373 |
| 30 | (Per SFAS No. 158 adopted 12/31/2006; | | | | | |
| 31 | OPUC Order No. 07-051 dtd 2/12/2007) | | | | | |
| 32 | | | | | | |
| 33 | Lease Obligation Balancing Account | 751,148 | | | 405,656 | 1,156,804 |
| 34 | | | | | | |
| 35 | Direct Access Deferral - 2019 | 1,074,500 | 431/447 | 904,310 | 26,187 | 196,377 |
| 36 | (Per UM-1301, Order No. 19-045 | | | | | |
| 37 | dated 12/30/2019) | | | | | |
| 38 | | | | | | |
| 39 | Direct Access Deferral - 2020 | | | | 400,316 | 400,316 |
| 40 | (Per UM-1301, Order No. 21-034 | | | | | |
| 41 | TOTAL | 408,556,713 | | 151,854,371 | 164,712,767 | 421,415,109 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2020/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 | dated 1/28/2021) | | | | | |
| 2 | | | | | | |
| 3 | OCAT | | 182.3 | 2,832,008 | 2,832,008 | |
| 4 | (Per UM-2037, UE 368, Order No. | | | | | |
| 5 | 20-029, dtd 01/29/2020) | | | | | |
| 6 | | | | | | |
| 7 | Monet NVPC QF Deferral 2020 | | 555 | 1,560,699 | 3,374,475 | 1,813,776 |
| 8 | (Per UM-1988, Order No. 19-441 | | | | | |
| 9 | dtd 12/20/2019) | | | | | |
| 10 | | | | | | |
| 11 | Residual Account | | 182.3 | 185,000 | 102,182 | -82,818 |
| 12 | | | | | | |
| 13 | Demand Response Testbed | | 182.3 | 2,650,045 | 4,935,499 | 2,285,454 |
| 14 | (Per OPUC Order No. 19-425, dtd 12/06/2019) | | | | | |
| 15 | (Amortization period 1/1/2020-12/31/2020) | | | | | |
| 16 | | | | | | |
| 17 | Residential Sch123 SNA Deferral-2020 | | 431 | 9,165 | 15,084,407 | 15,075,242 |
| 18 | (Reauthorized Advice No. 16-23, | | | | | |
| 19 | dtd 11/23/2016) | | | | | |
| 20 | | | | | | |
| 21 | Automated Demand Response Cost | | 182.3 | 535,791 | 535,791 | |
| 22 | (Per OPUC Advice No. 17-29, dtd 11/13/17) | | | | | |
| 23 | (Amortization period 1/1/2020-12/31/2020) | | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
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| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL | 408,556,713 | | 151,854,371 | 164,712,767 | 421,415,109 |

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

***Schedule Page: 278 Line No.: 9 Column: c***

101/108/165/228.2/254/407.3/456/924/925

***Schedule Page: 278 Line No.: 16 Column: b***

Beginning balance includes $469,146 reclassification to PW1 MMA.

***Schedule Page: 278 Line No.: 20 Column: b***

Beginning balance is made up of a reclassification from Colstrip MMA.

## 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 | 969,909,454 | 917,792,335 |
| 3 | (442) Commercial and Industrial Sales | | |
| 4 | Small (or Comm.) (See Instr. 4) | 619,175,770 | 638,317,031 |
| 5 | Large (or Ind.) (See Instr. 4) | 246,051,284 | 221,934,941 |
| 6 | (444) Public Street and Highway Lighting | 10,945,945 | 11,259,467 |
| 7 | (445) Other Sales to Public Authorities | | |
| 8 | (446) Sales to Railroads and Railways | | |
| 9 | (448) Interdepartmental Sales | | |
| 10 | TOTAL Sales to Ultimate Consumers | 1,846,082,453 | 1,789,303,774 |
| 11 | (447) Sales for Resale | 184,596,850 | 203,335,776 |
| 12 | TOTAL Sales of Electricity | 2,030,679,303 | 1,992,639,550 |
| 13 | (Less) (449.1) Provision for Rate Refunds | -5,767,072 | -24,671,723 |
| 14 | TOTAL Revenues Net of Prov. for Refunds | 2,036,446,375 | 2,017,311,273 |
| 15 | Other Operating Revenues | | |
| 16 | (450) Forfeited Discounts | 1,510,490 | 7,533,569 |
| 17 | (451) Miscellaneous Service Revenues | 917,276 | 1,918,764 |
| 18 | (453) Sales of Water and Water Power | -20,340 | -25,668 |
| 19 | (454) Rent from Electric Property | 13,829,360 | 11,854,326 |
| 20 | (455) Interdepartmental Rents | | |
| 21 | (456) Other Electric Revenues | 94,787,137 | 98,951,224 |
| 22 | (456.1) Revenues from Transmission of Electricity of Others | 9,742,070 | 10,438,921 |
| 23 | (457.1) Regional Control Service Revenues | | |
| 24 | (457.2) Miscellaneous Revenues | | |
| 25 | | | |
| 26 | TOTAL Other Operating Revenues | 120,765,993 | 130,671,136 |
| 27 | TOTAL Electric Operating Revenues | 2,157,212,368 | 2,147,982,409 |

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 |
| 7,756,251 | 7,471,069 | 791,119 | 779,673 | 2 |
| | | | | 3 |
| 6,173,372 | 6,603,269 | 110,654 | 109,890 | 4 |
| 3,445,801 | 3,180,993 | 267 | 262 | 5 |
| 48,379 | 49,360 | 197 | 194 | 6 |
| | | | | 7 |
| | | | | 8 |
| | | | | 9 |
| 17,423,803 | 17,304,691 | 902,237 | 890,019 | 10 |
| 6,442,580 | 5,267,311 | 40 | 35 | 11 |
| 23,866,383 | 22,572,002 | 902,277 | 890,054 | 12 |
| | | | | 13 |
| 23,866,383 | 22,572,002 | 902,277 | 890,054 | 14 |

Line 12, column (b) includes $ 10,618,000 of unbilled revenues.

Line 12, column (d) includes 83,623 MWH relating to unbilled revenues

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

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

Includes $18,367,467 in revenue related to the delivery of 632,946 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 2020, 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 $18,052,199 in revenue related to the delivery of 665,844 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 2019, 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 $27,601,676 in revenue related to the delivery of 1,486,266 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2020, 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 $25,500,018 in revenue related to the delivery of 1,489,711 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2019, 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

***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

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

| **Other Electric Revenues consist of the following:** | **Q4-2020** |
|---|---|
| Boardman Decommissioning Balancing Account | (2,800) |
| Boardman Ops | 217,435 |
| Boardman Severance | 2,343,630 |
| Carty Major Maintenance Deferral | (648,342) |
| Colstrip - Major Maint Accrual/Defr | 129,151 |
| Hydro License Implementation and Compliance | 816,290 |
| Lost Revenue Recovery | 272,039 |
| MCI Metro | 5,342,471 |
| Other | 673,727 |
| PW1 - Major Maint Deferral | (1,764,825) |
| PW2 - Major Maint Deferral | (968,678) |
| RPA Balancing | 63,144,577 |
| Steam Sales | 1,419,239 |
| Transmission Resale | 7,246,772 |
| Gas Resale | 441,617 |
| ETO Management | 17,567 |
| Sch. 7 Norm Adj | (2,166,598) |
| Sch. 32 Norm Adj | 4,168,945 |
| Sch. 83 Norm Adj | 5,537,665 |
| Accumulated ARO Boardman | 8,567,256 |
| **Grand Total** | **94,787,137** |

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

| **Other Electric Revenues consist of the following:** | **Q4-2019** |
|---|---|
| 2019 ETO Management | 106,421 |
| Boardman Decommissioning Balancing Account | (132,836) |
| Boardman Ops | 176,527 |
| Boardman Severance | (227,993) |
| Carty Major Maintenance Deferral | 257,225 |
| Colstrip - Major Maint Accrual/Defr | (2,795,622) |
| CSP Major Maintenance Deferral | 3,146,462 |
| Hydro License Implementation and Compliance | 885,524 |
| Lost Revenue Recovery | (1,115,160) |
| MCI Metro | 5,121,090 |
| Other | 1,203,676 |
| PW1 - Major Maint Deferral | (469,146) |
| PW2 - Major Maint Deferral | (181,982) |
| RPA Balancing | 67,208,725 |

| | |
|---|---|
| Sch 7 Sales Norm Adj | (2,960,236) |
| Sch 83 Sales Norm Adj. | 2,547,830 |
| Steam Sales | 1,874,091 |
| Transport Electrification | 7,085 |
| Transmission Resale | 6,997,356 |
| Gas Resale | 17,302,187 |
| **Grand Total** | **98,951,224** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2020/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 | | | | | |
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| 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<br>(2) [ ] A Resubmission | // | End of 2020/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 | (1) Residential | | | | | |
| 2 | 6-Residential Pricing Pilot | -9 | -1,022 | 1 | -9,000 | 0.1136 |
| 3 | 7-Residential Service | 7,708,344 | 962,437,119 | 791,118 | 9,744 | 0.1249 |
| 4 | 15-Outdoor Area Lighting | 1,749 | 657,357 | | | 0.3758 |
| 5 | (1) Residential Unbilled | 46,167 | 6,816,000 | | | 0.1476 |
| 6 | TOTAL Account 440 | 7,756,251 | 969,909,454 | 791,119 | 9,804 | 0.1250 |
| 7 | (3) General Comm. & Ind. | | | | | |
| 8 | 15-Outdoor Area Lighting | 13,095 | 2,732,035 | | | 0.2086 |
| 9 | 32-Small Nonresidential | 1,484,227 | 175,616,522 | 92,905 | 15,976 | 0.1183 |
| 10 | 38-Large Nonresidential | 25,672 | 3,447,577 | 370 | 69,384 | 0.1343 |
| 11 | 47-Small Irrigation & Drainage | 16,537 | 3,384,025 | 2,730 | 6,058 | 0.2046 |
| 12 | 49-Large Irrigation & Drainage | 53,462 | 7,692,135 | 1,399 | 38,214 | 0.1439 |
| 13 | 83-Large Nonresidential | 2,670,059 | 249,480,338 | 11,501 | 232,159 | 0.0934 |
| 14 | 85-Large Nonresidential | 1,894,824 | 155,942,544 | 1,183 | 1,601,711 | 0.0823 |
| 15 | 89-Large Nonresidential | 5,494 | 542,949 | 1 | 5,494,000 | 0.0988 |
| 16 | 485-Large Nonresidential COS O | 4,523 | 336,359 | 3 | 1,507,667 | 0.0744 |
| 17 | 532-Small Nonresidential DAS | 4 | 308 | | | 0.0770 |
| 18 | 583-Large Nonresidential DAS | 73 | 3,493 | | | 0.0478 |
| 19 | 585-Large Nonresidential DAS | | 4,324 | | | |
| 20 | (3) ESS General Comm. & Ind. | | | | | |
| 21 | 83-Large Nonresidential | | | 2 | | |
| 22 | 485-Large Nonresidential COS O | | 11,857,141 | 226 | | |
| 23 | 489-Large Nonresidential COS O | | 299,906 | 1 | | |
| 24 | 515-Outdoor Area Lighting DAS | | 5,768 | | | |
| 25 | 532-Small Nonresidential DAS | | 430,896 | 174 | | |
| 26 | 538-Large Nonresidential Opt. | | 2,862 | 2 | | |
| 27 | 583-Large Nonresidential DAS | | 2,174,514 | 115 | | |
| 28 | 585-Large Nonresidential DAS | | 3,433,074 | 42 | | |
| 29 | (3) General Comm. & Ind. Unbilled | 5,402 | 1,789,000 | | | 0.3312 |
| 30 | TOTAL Account 442 - Small | 6,173,372 | 619,175,770 | 110,654 | 55,790 | 0.1003 |
| 31 | (4) Large Ind. & Trans. | | | | | |
| 32 | 89-Large Nonresidential | 117,256 | 8,289,582 | 6 | 19,542,667 | 0.0707 |
| 33 | (4) ESS Large Ind. & Trans. | | | | | |
| 34 | 489-Large Nonresidential COS O | | 1,042,038 | 2 | | |
| 35 | (4) Large Ind. & Trans. Unbilled | 1,787 | 76,000 | | | 0.0425 |
| 36 | (5) Large Comm. & Ind. | | | | | |
| 37 | 32-Small Nonresidential | | | | | |
| 38 | 83-Large Nonresidential | | | | | |
| 39 | 85-Large Nonresidential | 610,007 | 45,896,358 | 170 | 3,588,276 | 0.0752 |
| 40 | 89-Large Nonresidential | 420,115 | 27,495,597 | 12 | 35,009,583 | 0.0654 |
| 41 | TOTAL Billed | 17,340,180 | 1,835,464,453 | 902,237 | 19,219 | 0.1059 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 83,623 | 10,618,000 | 0 | 0 | 0.1270 |
| 43 | TOTAL | 17,423,803 | 1,846,082,453 | 902,237 | 19,312 | 0.1060 |

## 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 | 90-Large Nonresidential | 2,257,511 | 133,323,120 | 5 | 451,502,200 | 0.0591 |
| 2 | 485-Large Nonresidential COS O | 1,864 | 129,097 | | | 0.0693 |
| 3 | 489-Large Nonresidential COS O | 3,339 | 219,340 | | | 0.0657 |
| 4 | 689-New Large Load COS Opt-Out | 219 | 11,002 | | | 0.0502 |
| 5 | (5) ESS Large Comm. & Ind. | | | | | |
| 6 | 485-Larrge Nonresidential COS | | 7,258,620 | 53 | | |
| 7 | 489-Large Nonresidential COS O | | 18,752,339 | 14 | | |
| 8 | 585-Large Nonresidential DAS | | 703,397 | 4 | | |
| 9 | 689-New Large Load COS Opt-Out | | 51,794 | 1 | | |
| 10 | (5) Large Comm. & Ind. Unbilled | 33,703 | 2,803,000 | | | 0.0832 |
| 11 | TOTAL Account 442 - Large | 3,445,801 | 246,051,284 | 267 | 12,905,622 | 0.0714 |
| 12 | (6) Street Lighting | | | | | |
| 13 | 91-Street & Hwy Lighting | 24,000 | 6,682,606 | 180 | 133,333 | 0.2784 |
| 14 | 92-Traffic Signals | 2,655 | 223,437 | 16 | 165,938 | 0.0842 |
| 15 | 95-Street & Hwy Lighting (New | 25,161 | 4,905,902 | 1 | 25,161,000 | 0.1950 |
| 16 | (6) Street Lighting Unbilled | -3,437 | -866,000 | | | 0.2520 |
| 17 | TOTAL Account 444 | 48,379 | 10,945,945 | 197 | 245,579 | 0.2263 |
| 18 | Other Sales to Public Authorities | | | | | |
| 19 | TOTAL Account 445 | | | | | |
| 20 | Sales to Railroads and Railways | | | | | |
| 21 | TOTAL Account 446 | | | | | |
| 22 | Interdepartmental Sales | | | | | |
| 23 | TOTAL Account 448 | | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | | | | | |
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| 35 | | | | | | |
| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL Billed | 17,340,180 | 1,835,464,453 | 902,237 | 19,219 | 0.1059 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 83,623 | 10,618,000 | 0 | 0 | 0.1270 |
| 43 | TOTAL | 17,423,803 | 1,846,082,453 | 902,237 | 19,312 | 0.1060 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | // | End of 2020/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.
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SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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| Line No. | Name of Company or Public Authority (Footnote Affiliations) | Statistical Classifi-cation | FERC Rate Schedule or Tariff Number | Average Monthly Billing Demand (MW) | Actual Demand (MW) | |
|---|---|---|---|---|---|---|
| | | | | | Average Monthly NCP Demand | Average Monthly CP Demand |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Avangrid Renewables (was Iberdrola) | SF | EEI | NA | NA | NA |
| 2 | Avista Corp. | SF | WSPP-1 | NA | NA | NA |
| 3 | BP Energy Company | SF | PGE-11 | NA | NA | NA |
| 4 | Black Hills Power | SF | WSPP-1 | NA | NA | NA |
| 5 | Bonneville Power Administration | SF | WSPP-1 | NA | NA | NA |
| 6 | British Columbia Hydro & Power Authoiry | SF | WSPP-1 | NA | NA | NA |
| 7 | Brookfield Energy Marketing LP | SF | WSPP-1 | NA | NA | NA |
| 8 | California Independent System Operator | SF | CAISO | NA | NA | NA |
| 9 | Calpine Energy Services, L.P. | SF | EEI | NA | NA | NA |
| 10 | Calpine Energy Services, L.P. | OS | WSPP-1 | NA | NA | NA |
| 11 | Chelan County, PUD No. 1, Washington | SF | WSPP-1 | NA | NA | NA |
| 12 | Citigroup Energy Inc. | SF | WSPP-1 | NA | NA | NA |
| 13 | City of Burbank | SF | WSPP-1 | NA | NA | NA |
| 14 | City of Glendale | 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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|---|---|---|---|---|---|---|
| | | | | | Average Monthly NCP Demand | Average Monthly CP Demand |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | City of Corona | OS | WSPP-1 | NA | NA | NA |
| 2 | City of Industry | OS | WSPP-1 | NA | NA | NA |
| 3 | City of Redding | SF | WSPP-1 | NA | NA | NA |
| 4 | City of Roseville | SF | WSPP-1 | NA | NA | NA |
| 5 | Clatskanie Peoples Utility District | SF | WSPP-1 | NA | NA | NA |
| 6 | Clean Power Alliance | OS | WSPP-1 | NA | NA | NA |
| 7 | ConocoPhillips Company | SF | WSPP-1 | NA | NA | NA |
| 8 | Direct Energy Business Marketing | SF | WSPP-1 | NA | NA | NA |
| 9 | Direct Energy Business Marketing | OS | WSPP-1 | NA | NA | NA |
| 10 | Douglas County, PUD No. 1, Washington | SF | WSPP-1 | NA | NA | NA |
| 11 | DTE Energy Trading LLC | SF | WSPP-1 | NA | NA | NA |
| 12 | Desert Community Energy | OS | WSPP-1 | NA | NA | NA |
| 13 | EAST BAY COMMUNITY ENERGY | OS | WSPP-1 | NA | NA | NA |
| 14 | EDF Trading North America, LLC | 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 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 | Element Markets | OS | EEI | NA | NA | NA |
| 2 | Energy Keepers, Inc. | SF | WSPP-1 | NA | NA | NA |
| 3 | Eugene Water & Electric Board | SF | WSPP-1 | NA | NA | NA |
| 4 | Exelon Generation Company, LLC | SF | EEI | NA | NA | NA |
| 5 | Gridforce Energy Management | SF | WSPP-1 | NA | NA | NA |
| 6 | Idaho Power Company | SF | WSPP-1 | NA | NA | NA |
| 7 | Load Balance Energy | OS | OATT | NA | NA | NA |
| 8 | Los Angeles Dept. Water Power | SF | WSPP-1 | NA | NA | NA |
| 9 | Los Angeles Dept. Water Power | OS | WSPP-1 | NA | NA | NA |
| 10 | Macquarie Energy LLC | SF | WSPP-1 | NA | NA | NA |
| 11 | Morgan Stanley Capital Group, Inc. | SF | PGE-11 | NA | NA | NA |
| 12 | NaturEner Power Watch, LLC | SF | WSPP-1 | NA | NA | NA |
| 13 | NextEra Energy Power Marketing, LLC | SF | WSPP-1 | NA | NA | NA |
| 14 | NorthWestern Corporation | 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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| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | PacifiCorp | SF | EEI | NA | NA | NA |
| 2 | PacifiCorp | LU | PGE-11 | NA | NA | NA |
| 3 | Pacific Northwest Generating Company | SF | WSPP-1 | NA | NA | NA |
| 4 | Powerex Corp. | SF | EEI | NA | NA | NA |
| 5 | Pend Orielle County PUD | SF | WSPP-1 | NA | NA | NA |
| 6 | Public Service Company of Colorado | SF | WSPP-1 | NA | NA | NA |
| 7 | Public Utility District No. 1 of Okanoy | SF | WSPP-1 | NA | NA | NA |
| 8 | Public Utility District No. 2 of Granty | SF | WSPP-1 | NA | NA | NA |
| 9 | Puget Sound Energy | SF | WSPP-1 | NA | NA | NA |
| 10 | Rainbow Energy Marketing Company | SF | WSPP-1 | NA | NA | NA |
| 11 | San Diego Gas & Electric | SF | WSPP-1 | NA | NA | NA |
| 12 | San Jose Clean Energy | OS | WSPP-1 | NA | NA | NA |
| 13 | Sacramento Municipal Utility District | SF | WSPP-1 | NA | NA | NA |
| 14 | Sacramento Municipal Utility District | OS | WSPP-1 | NA | NA | NA |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

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|---|---|---|---|---|---|---|
| | | | | | Average Monthly NCP Demand | Average Monthly CP Demand |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Seattle City Light | SF | WSPP-1 | NA | NA | NA |
| 2 | Shell Energy North America (US), L.P. | SF | PGE-11 | NA | NA | NA |
| 3 | Snohomish County, PUD No.1, Washington | SF | WSPP-1 | NA | NA | NA |
| 4 | Southern California Edison | SF | EEI | NA | NA | NA |
| 5 | Tacoma Power | SF | WSPP-1 | NA | NA | NA |
| 6 | Tenaska Power Services Co. | SF | WSPP-1 | NA | NA | NA |
| 7 | The Energy Authority, Inc. | SF | WSPP-1 | NA | NA | NA |
| 8 | TransAlta Energy Marketing (U.S.), Inc. | SF | EEI | NA | NA | NA |
| 9 | TransCanada Energy Sales Ltd. | SF | WSPP-1 | NA | NA | NA |
| 10 | Turlock Irrigation District | SF | WSPP-1 | NA | NA | NA |
| 11 | Vitol Inc. | SF | WSPP-1 | NA | NA | NA |
| 12 | Wheatridge Wind II, LLC | LU | WSPP-1 | NA | NA | NA |
| 13 | Western Area Power Authority | SF | WSPP-1 | NA | NA | NA |
| 14 | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

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



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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)<br>(a) | Statistical Classification<br>(b) | FERC Rate Schedule or Tariff Number<br>(c) | Average Monthly Billing Demand (MW)<br>(d) | Actual Demand (MW) Average Monthly NCP Demand<br>(e) | Actual Demand (MW) Average Monthly CP Demand<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Direct Access deferral 2020 | | | NA | NA | NA |
| 2 | Direct Access amortization 2020 | | | NA | NA | NA |
| 3 | | | | | | |
| 4 | Non-RQ Sales: | | | | | |
| 5 | | | | | | |
| 6 | Portland General Electric Company | SF | OA96137 | 926 | NA | NA |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

SALES FOR RESALE (Account 447) (Continued)

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

| MegaWatt Hours Sold<br>(g) | REVENUE<br>Demand Charges ($)<br>(h) | Energy Charges ($)<br>(i) | Other Charges ($)<br>(j) | Total ($) (h+i+j)<br>(k) | Line No. |
|---|---|---|---|---|---|
| 218,061 | | 6,043,017 | | 6,043,017 | 1 |
| 30,665 | | 871,269 | | 871,269 | 2 |
| 52,636 | | 1,116,766 | | 1,116,766 | 3 |
| 13,493 | | 1,302,389 | | 1,302,389 | 4 |
| 192,049 | | 4,603,034 | | 4,603,034 | 5 |
| 37 | | 866 | | 866 | 6 |
| 2,640 | | 66,162 | | 66,162 | 7 |
| 2,773,488 | | 55,590,215 | | 55,590,215 | 8 |
| 14,530 | | 459,618 | | 459,618 | 9 |
| | | | 716,172 | 716,172 | 10 |
| 7 | | 106 | | 106 | 11 |
| 9,537 | | 1,363,572 | | 1,363,572 | 12 |
| 2,305 | | 80,360 | | 80,360 | 13 |
| 2,643 | | 70,250 | | 70,250 | 14 |
| | | | | | |
| 0 | 0 | 0 | 0 | 0 | |
| 6,442,580 | 7,067,263 | 158,728,222 | 18,801,365 | 184,596,850 | |
| **6,442,580** | **7,067,263** | **158,728,222** | **18,801,365** | **184,596,850** | |

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. |
|---|---|---|---|---|---|
| | | | 916,050 | 916,050 | 1 |
| | | | 573,500 | 573,500 | 2 |
| 5,950 | | 155,325 | | 155,325 | 3 |
| 218,775 | | 9,497,921 | | 9,497,921 | 4 |
| 848 | | 24,041 | | 24,041 | 5 |
| | | | 657,155 | 657,155 | 6 |
| 182,785 | | 4,532,393 | | 4,532,393 | 7 |
| 33,105 | | 1,564,207 | | 1,564,207 | 8 |
| | | | 362,500 | 362,500 | 9 |
| 168,700 | | 47,679 | | 47,679 | 10 |
| 100,606 | | 2,884,426 | | 2,884,426 | 11 |
| | | | 42,560 | 42,560 | 12 |
| | | | 2,980,790 | 2,980,790 | 13 |
| 24,003 | | 689,560 | | 689,560 | 14 |
| | | | | | |
| 0 | 0 | 0 | 0 | 0 | |
| 6,442,580 | 7,067,263 | 158,728,222 | 18,801,365 | 184,596,850 | |
| **6,442,580** | **7,067,263** | **158,728,222** | **18,801,365** | **184,596,850** | |

SALES FOR RESALE (Account 447) (Continued)

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

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| | | | 544,501 | 544,501 | 1 |
| 321,815 | | 8,868,127 | | 8,868,127 | 2 |
| 19,526 | | 402,202 | | 402,202 | 3 |
| 41,226 | | 909,256 | | 909,256 | 4 |
| 257 | | 6,069 | | 6,069 | 5 |
| 32,425 | | 507,828 | | 507,828 | 6 |
| 32,546 | | | | | 7 |
| 33,055 | | 1,089,528 | | 1,089,528 | 8 |
| | | | 363,605 | 363,605 | 9 |
| 91,838 | | 2,259,769 | | 2,259,769 | 10 |
| 75,288 | | 2,802,691 | | 2,802,691 | 11 |
| 224 | | 5,309 | | 5,309 | 12 |
| 3,356 | | 86,562 | | 86,562 | 13 |
| 51,449 | | 1,391,076 | | 1,391,076 | 14 |
| 0 | 0 | 0 | 0 | 0 | |
| 6,442,580 | 7,067,263 | 158,728,222 | 18,801,365 | 184,596,850 | |
| **6,442,580** | **7,067,263** | **158,728,222** | **18,801,365** | **184,596,850** | |

SALES FOR RESALE (Account 447) (Continued)

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4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

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

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

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

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

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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. |
|---|---|---|---|---|---|
| 79,076 | | 2,296,467 | | 2,296,467 | 1 |
| 17,020 | | 116,628 | | 116,628 | 2 |
| 109,150 | | 3,313,138 | | 3,313,138 | 3 |
| 46,016 | | 1,008,046 | | 1,008,046 | 4 |
| 188,155 | | 3,230,693 | | 3,230,693 | 5 |
| 400 | | 7,900 | | 7,900 | 6 |
| 1,408 | | 66,920 | | 66,920 | 7 |
| 228,357 | | 6,926,774 | | 6,926,774 | 8 |
| 167,934 | | 5,964,564 | | 5,964,564 | 9 |
| 2,236 | | 58,745 | | 58,745 | 10 |
| 9,995 | | 414,793 | | 414,793 | 11 |
| | | | 6,914,137 | 6,914,137 | 12 |
| 4,626 | | 738,772 | | 738,772 | 13 |
| | | | 4,068,336 | 4,068,336 | 14 |
| 0 | 0 | 0 | 0 | 0 | |
| 6,442,580 | 7,067,263 | 158,728,222 | 18,801,365 | 184,596,850 | |
| **6,442,580** | **7,067,263** | **158,728,222** | **18,801,365** | **184,596,850** | |

SALES FOR RESALE (Account 447) (Continued)

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5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
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.
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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. |
|---|---|---|---|---|---|
| 22,873 | | 616,775 | | 616,775 | 1 |
| 63,715 | | 1,589,730 | | 1,589,730 | 2 |
| 19,790 | | 504,048 | | 504,048 | 3 |
| 214,879 | | 11,922,556 | | 11,922,556 | 4 |
| 40,497 | | 1,064,191 | | 1,064,191 | 5 |
| 252,214 | | 4,826,129 | | 4,826,129 | 6 |
| 48,884 | | 1,419,318 | | 1,419,318 | 7 |
| 102,255 | | 2,738,304 | | 2,738,304 | 8 |
| 60,199 | | 1,146,691 | | 1,146,691 | 9 |
| 10,239 | | 431,940 | | 431,940 | 10 |
| 2,000 | | 50,036 | | 50,036 | 11 |
| | | -1,045,524 | | -1,045,524 | 12 |
| 794 | | 28,995 | | 28,995 | 13 |
| | | | | | 14 |
| 0 | 0 | 0 | 0 | 0 | |
| 6,442,580 | 7,067,263 | 158,728,222 | 18,801,365 | 184,596,850 | |
| **6,442,580** | **7,067,263** | **158,728,222** | **18,801,365** | **184,596,850** | |

SALES FOR RESALE (Account 447) (Continued)

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

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.

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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. |
|---|---|---|---|---|---|
| | | | -400,320 | -400,320 | 1 |
| | | | 1,062,379 | 1,062,379 | 2 |
| | | | | | 3 |
| | | | | | 4 |
| | | | | | 5 |
| | 7,067,263 | | | 7,067,263 | 6 |
| | | | | | 7 |
| | | | | | 8 |
| | | | | | 9 |
| | | | | | 10 |
| | | | | | 11 |
| | | | | | 12 |
| | | | | | 13 |
| | | | | | 14 |
| 0 | 0 | 0 | 0 | 0 | |
| 6,442,580 | 7,067,263 | 158,728,222 | 18,801,365 | 184,596,850 | |
| **6,442,580** | **7,067,263** | **158,728,222** | **18,801,365** | **184,596,850** | |

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

***Schedule Page: 310 Line No.: 10 Column: j***
Represents sales of renewable energy credits to Calpine.
***Schedule Page: 310.1 Line No.: 1 Column: j***
Represents sales of renewable energy credits to City of Corona
***Schedule Page: 310.1 Line No.: 2 Column: j***
Represents sales of renewable energy credits to City of Industry
***Schedule Page: 310.1 Line No.: 6 Column: j***
Represents sales of renewable energy credits to Clean Power Alliance
***Schedule Page: 310.1 Line No.: 9 Column: j***
Represents sales of renewable energy credits to Direct Business Energy Marketing
***Schedule Page: 310.1 Line No.: 12 Column: j***
Represents sales of renewable energy credits to Desert Community Energy
***Schedule Page: 310.1 Line No.: 13 Column: j***
Represents sales of renewable energy credits to
EAST BAY COMMUNITY ENERGY AUTHORITY
***Schedule Page: 310.2 Line No.: 1 Column: j***
Represents sales of renewable energy credits to Element Market
***Schedule Page: 310.2 Line No.: 9 Column: j***
Represents sales of renewable energy credits to Los Angeles Dept. Water Power
***Schedule Page: 310.3 Line No.: 2 Column: b***
Estimated Round Butte plant operating expenses (Cove Dam replacement power).
***Schedule Page: 310.3 Line No.: 12 Column: j***
Represents sales of renewable energy credits to San Jose Clean Energy
***Schedule Page: 310.3 Line No.: 14 Column: j***
Represents sales of renewable energy credits to Sacramento Municipal Utility District
***Schedule Page: 310.4 Line No.: 12 Column: i***
Wheatridge II Test Energy reclassed to capital
***Schedule Page: 310.5 Line No.: 1 Column: j***
Defer costs associated with the implementation of the annual
direct access open enrollment window. See Tariff Schedule 128 filed 01/26/2007.
***Schedule Page: 310.5 Line No.: 2 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.: 6 Column: a***
Represents Portland General Electric Companys use of Portland
General Electric Company's Open Access Transmission
System. This is included in Account 447 based on guidance
from FERC Deputy Chief Accountant - issued January 1996.

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



ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 1 | 1. POWER PRODUCTION EXPENSES | | |
| 2 | A. Steam Power Generation | | |
| 3 | Operation | | |
| 4 | (500) Operation Supervision and Engineering | 2,351,045 | 2,330,701 |
| 5 | (501) Fuel | 70,676,152 | 93,517,673 |
| 6 | (502) Steam Expenses | 15,834,155 | 8,506,261 |
| 7 | (503) Steam from Other Sources | | |
| 8 | (Less) (504) Steam Transferred-Cr. | | |
| 9 | (505) Electric Expenses | | |
| 10 | (506) Miscellaneous Steam Power Expenses | 7,903,659 | 11,103,441 |
| 11 | (507) Rents | | 16,802 |
| 12 | (509) Allowances | | |
| 13 | TOTAL Operation (Enter Total of Lines 4 thru 12) | 96,765,011 | 115,474,878 |
| 14 | Maintenance | | |
| 15 | (510) Maintenance Supervision and Engineering | 964,898 | 901,629 |
| 16 | (511) Maintenance of Structures | 993,652 | 1,099,748 |
| 17 | (512) Maintenance of Boiler Plant | 8,181,488 | 6,475,812 |
| 18 | (513) Maintenance of Electric Plant | 5,096,511 | 7,623,269 |
| 19 | (514) Maintenance of Miscellaneous Steam Plant | 836,609 | 936,102 |
| 20 | TOTAL Maintenance (Enter Total of Lines 15 thru 19) | 16,073,158 | 17,036,560 |
| 21 | TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20) | 112,838,169 | 132,511,438 |
| 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 | 787,010 | 924,616 |
| 45 | (536) Water for Power | 608,858 | 603,680 |
| 46 | (537) Hydraulic Expenses | 7,149,131 | 7,127,838 |
| 47 | (538) Electric Expenses | 1,701,819 | 1,630,458 |
| 48 | (539) Miscellaneous Hydraulic Power Generation Expenses | 3,375,138 | 4,037,198 |
| 49 | (540) Rents | 809,334 | 777,790 |
| 50 | TOTAL Operation (Enter Total of Lines 44 thru 49) | 14,431,290 | 15,101,580 |
| 51 | C. Hydraulic Power Generation (Continued) | | |
| 52 | Maintenance | | |
| 53 | (541) Mainentance Supervision and Engineering | 994,464 | 753,270 |
| 54 | (542) Maintenance of Structures | 4,894 | |
| 55 | (543) Maintenance of Reservoirs, Dams, and Waterways | 362,086 | 1,263,061 |
| 56 | (544) Maintenance of Electric Plant | 1,355,885 | 1,313,156 |
| 57 | (545) Maintenance of Miscellaneous Hydraulic Plant | 1,580,035 | 1,077,945 |
| 58 | TOTAL Maintenance (Enter Total of lines 53 thru 57) | 4,297,364 | 4,407,432 |
| 59 | TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58) | 18,728,654 | 19,509,012 |

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 | 3,369,465 | 3,719,373 |
| 63 | (547) Fuel | 170,765,398 | 194,396,475 |
| 64 | (548) Generation Expenses | 8,506,242 | 8,894,822 |
| 65 | (549) Miscellaneous Other Power Generation Expenses | 13,416,046 | 19,499,593 |
| 66 | (550) Rents | 944,505 | 1,000,732 |
| 67 | TOTAL Operation (Enter Total of lines 62 thru 66) | 197,001,656 | 227,510,995 |
| 68 | Maintenance | | |
| 69 | (551) Maintenance Supervision and Engineering | 1,686,939 | 1,860,170 |
| 70 | (552) Maintenance of Structures | 292,574 | 534,328 |
| 71 | (553) Maintenance of Generating and Electric Plant | 30,378,456 | 44,669,783 |
| 72 | (554) Maintenance of Miscellaneous Other Power Generation Plant | 1,037,697 | 1,097,144 |
| 73 | TOTAL Maintenance (Enter Total of lines 69 thru 72) | 33,395,666 | 48,161,425 |
| 74 | TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73) | 230,397,322 | 275,672,420 |
| 75 | E. Other Power Supply Expenses | | |
| 76 | (555) Purchased Power | 418,799,466 | 281,457,582 |
| 77 | (556) System Control and Load Dispatching | 238,013 | 250,780 |
| 78 | (557) Other Expenses | 21,170,453 | 22,883,439 |
| 79 | TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78) | 440,207,932 | 304,591,801 |
| 80 | TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79) | 802,172,077 | 732,284,671 |
| 81 | 2. TRANSMISSION EXPENSES | | |
| 82 | Operation | | |
| 83 | (560) Operation Supervision and Engineering | 7,440,319 | 7,644,678 |
| 84 | | | |
| 85 | (561.1) Load Dispatch-Reliability | 16,150 | 14,627 |
| 86 | (561.2) Load Dispatch-Monitor and Operate Transmission System | 1,053,301 | 961,011 |
| 87 | (561.3) Load Dispatch-Transmission Service and Scheduling | 1,400,410 | 1,512,133 |
| 88 | (561.4) Scheduling, System Control and Dispatch Services | | |
| 89 | (561.5) Reliability, Planning and Standards Development | | |
| 90 | (561.6) Transmission Service Studies | | 8,813 |
| 91 | (561.7) Generation Interconnection Studies | 195,430 | |
| 92 | (561.8) Reliability, Planning and Standards Development Services | | |
| 93 | (562) Station Expenses | 290,541 | 206,486 |
| 94 | (563) Overhead Lines Expenses | 313,338 | 175,946 |
| 95 | (564) Underground Lines Expenses | | |
| 96 | (565) Transmission of Electricity by Others | 81,280,168 | 83,561,883 |
| 97 | (566) Miscellaneous Transmission Expenses | 2,975,438 | 7,315,275 |
| 98 | (567) Rents | 2,908,566 | 3,574,527 |
| 99 | TOTAL Operation (Enter Total of lines 83 thru 98) | 97,873,661 | 104,975,379 |
| 100 | Maintenance | | |
| 101 | (568) Maintenance Supervision and Engineering | 10,247 | 20,563 |
| 102 | (569) Maintenance of Structures | | |
| 103 | (569.1) Maintenance of Computer Hardware | | |
| 104 | (569.2) Maintenance of Computer Software | 748,322 | 821,808 |
| 105 | (569.3) Maintenance of Communication Equipment | | |
| 106 | (569.4) Maintenance of Miscellaneous Regional Transmission Plant | | |
| 107 | (570) Maintenance of Station Equipment | 1,565,923 | 1,436,260 |
| 108 | (571) Maintenance of Overhead Lines | 1,326,886 | 1,299,193 |
| 109 | (572) Maintenance of Underground Lines | | |
| 110 | (573) Maintenance of Miscellaneous Transmission Plant | 778 | 3,483 |
| 111 | TOTAL Maintenance (Total of lines 101 thru 110) | 3,652,156 | 3,581,307 |
| 112 | TOTAL Transmission Expenses (Total of lines 99 and 111) | 101,525,817 | 108,556,686 |

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 | 17,715,664 | 26,332,943 |
| 135 | (581) Load Dispatching | 2,687,850 | 2,512,422 |
| 136 | (582) Station Expenses | 812,703 | 961,036 |
| 137 | (583) Overhead Line Expenses | 2,927,260 | 2,519,942 |
| 138 | (584) Underground Line Expenses | 4,218,614 | 3,648,832 |
| 139 | (585) Street Lighting and Signal System Expenses | 235,512 | 380,005 |
| 140 | (586) Meter Expenses | 2,292,043 | 3,086,554 |
| 141 | (587) Customer Installations Expenses | 3,021,147 | 3,885,491 |
| 142 | (588) Miscellaneous Expenses | 10,605,286 | 9,300,372 |
| 143 | (589) Rents | 1,687,489 | 1,978,035 |
| 144 | TOTAL Operation (Enter Total of lines 134 thru 143) | 46,203,568 | 54,605,632 |
| 145 | Maintenance | | |
| 146 | (590) Maintenance Supervision and Engineering | 37,138 | 44,098 |
| 147 | (591) Maintenance of Structures | 172,665 | 230,487 |
| 148 | (592) Maintenance of Station Equipment | 4,835,898 | 5,711,135 |
| 149 | (593) Maintenance of Overhead Lines | 55,034,683 | 51,687,071 |
| 150 | (594) Maintenance of Underground Lines | 8,069,382 | 9,429,811 |
| 151 | (595) Maintenance of Line Transformers | 1,881,127 | 2,571,576 |
| 152 | (596) Maintenance of Street Lighting and Signal Systems | 947,941 | 1,255,633 |
| 153 | (597) Maintenance of Meters | 5,790 | 51,996 |
| 154 | (598) Maintenance of Miscellaneous Distribution Plant | 6,817,818 | 9,030,454 |
| 155 | TOTAL Maintenance (Total of lines 146 thru 154) | 77,802,442 | 80,012,261 |
| 156 | TOTAL Distribution Expenses (Total of lines 144 and 155) | 124,006,010 | 134,617,893 |
| 157 | 5. CUSTOMER ACCOUNTS EXPENSES | | |
| 158 | Operation | | |
| 159 | (901) Supervision | | |
| 160 | (902) Meter Reading Expenses | 352,224 | 398,441 |
| 161 | (903) Customer Records and Collection Expenses | 50,657,698 | 55,772,614 |
| 162 | (904) Uncollectible Accounts | 7,069,010 | 2,155,688 |
| 163 | (905) Miscellaneous Customer Accounts Expenses | 5,547,635 | 6,944,625 |
| 164 | TOTAL Customer Accounts Expenses (Total of lines 159 thru 163) | 63,626,567 | 65,271,368 |

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 | 14,614,122 | 13,156,211 |
| 169 | (909) Informational and Instructional Expenses | 1,821,001 | 1,560,301 |
| 170 | (910) Miscellaneous Customer Service and Informational Expenses | | |
| 171 | TOTAL Customer Service and Information Expenses (Total 167 thru 170) | 16,435,123 | 14,716,512 |
| 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 | 80,315,704 | 81,318,578 |
| 182 | (921) Office Supplies and Expenses | 17,790,843 | 23,059,355 |
| 183 | (Less) (922) Administrative Expenses Transferred-Credit | 12,633,527 | 12,888,110 |
| 184 | (923) Outside Services Employed | 13,849,356 | 8,843,144 |
| 185 | (924) Property Insurance | 6,911,324 | 6,659,426 |
| 186 | (925) Injuries and Damages | 4,107,996 | 5,454,493 |
| 187 | (926) Employee Pensions and Benefits | 57,727,595 | 62,501,938 |
| 188 | (927) Franchise Requirements | | |
| 189 | (928) Regulatory Commission Expenses | 10,485,584 | 10,439,272 |
| 190 | (929) (Less) Duplicate Charges-Cr. | 2,325,928 | 2,769,908 |
| 191 | (930.1) General Advertising Expenses | 1,045,923 | 1,298,824 |
| 192 | (930.2) Miscellaneous General Expenses | 20,720,146 | 18,431,722 |
| 193 | (931) Rents | 3,914,762 | 4,604,944 |
| 194 | TOTAL Operation (Enter Total of lines 181 thru 193) | 201,909,778 | 206,953,678 |
| 195 | Maintenance | | |
| 196 | (935) Maintenance of General Plant | 2,785,844 | 3,295,290 |
| 197 | TOTAL Administrative & General Expenses (Total of lines 194 and 196) | 204,695,622 | 210,248,968 |
| 198 | TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197) | 1,312,461,216 | 1,265,696,098 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2020/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.

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

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

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

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

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| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Arizona Public | SF | WSPP-1 | NA | NA | NA |
| 2 | Airport Solar, LLC | LU | 201 | NA | NA | NA |
| 3 | Alkali Solar | LU | 201 | NA | NA | NA |
| 4 | Avangrid Renewables (was Iberdrola) | SF | PGE-11 | NA | NA | NA |
| 5 | Avangrid Renewables (was berdrola Ren) | LU | PGE-11 | NA | NA | NA |
| 6 | Avangrid Renewables (was Iberdrola) | LU | PGE-11 | NA | NA | NA |
| 7 | Avista Corp. - AVWP (was WWP) | SF | WSPP-1 | NA | NA | NA |
| 8 | BP Energy Company | SF | PGE-11 | NA | NA | NA |
| 9 | Ballston Solar | LU | 201 | NA | NA | NA |
| 10 | Bellevue Solar | LU | Bellevue | NA | NA | NA |
| 11 | Black Hills Power | SF | WSPP-1 | NA | NA | NA |
| 12 | Bonneville Power Administration | SF | WSPP-1 | NA | NA | NA |
| 13 | Boring Solar | LU | 201 | NA | NA | NA |
| 14 | Brookfield Energy Marketing | SF | WSPP-1 | NA | NA | NA |
| | Total | | | | | |

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

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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 | CP Energy Marketing (US) | SF | WSPP-1 | NA | NA | NA |
| 2 | California Independent System Operator | SF | CAISO | NA | NA | NA |
| 3 | Calpine Energy Services | SF | PGE-11 | NA | NA | NA |
| 4 | Case Creek Solar | LU | 201 | NA | NA | NA |
| 5 | Chelan County, PUD No. 1, Washington | SF | WSPP-1 | NA | NA | NA |
| 6 | Citigroup Energy | SF | WSPP-1 | NA | NA | NA |
| 7 | Burbank, City of | SF | WSPP-1 | NA | NA | NA |
| 8 | Clatskanie County PUD | SF | WSPP-1 | NA | NA | NA |
| 9 | ConocoPhillips | SF | WSPP-1 | NA | NA | NA |
| 10 | Constellation Energy Commodities | SF | PGE-11 | NA | NA | NA |
| 11 | Covanta Marion | LU | QF83-118 | NA | NA | NA |
| 12 | Douglas County, PUD No. 1, Washington | LF | Wells | NA | NA | NA |
| 13 | Douglas County, PUD No. 1, Washington | LF | WSPP-1 | NA | NA | NA |
| 14 | Douglas County, PUD No. 1, Washington | SF | WSPP-1 | NA | NA | NA |
| | Total | | | | | |

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



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

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|---|---|---|---|---|---|---|
| 1 | Douglas County, PUD No. 1, Washington | SF | WSPP-1 | NA | NA | NA |
| 2 | DTE Energy Trading, Inc. | SF | WSPP-1 | NA | NA | NA |
| 3 | EDF Trading North America, LLC | SF | WSPP-1 | NA | NA | NA |
| 4 | Enmax | SF | PGE-11 | NA | NA | NA |
| 5 | Energy Keepers, Inc. - ENKP | SF | WSPP-1 | NA | NA | NA |
| 6 | ESI Vansycle Partners, LP | LU | WSPP-1 | NA | NA | NA |
| 7 | Eugene Water & Electric Board | LU | WSPP-1 | NA | NA | NA |
| 8 | Eugene Water & Electric Board | SF | WSPP-1 | NA | NA | NA |
| 9 | Evergreen Biomass | LU | 201 | NA | NA | NA |
| 10 | Exelon Generation Co. | SF | WSPP-1 | NA | NA | NA |
| 11 | Falls Creek Hydro | LU | 201 | NA | NA | NA |
| 12 | Fort Rock Solar 1 | LU | 201 | NA | NA | NA |
| 13 | Fort Rock Solar 4 | LU | 201 | NA | NA | NA |
| 14 | Firwood Solar | LU | 201 | NA | NA | NA |
| | Total | | | | | |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Garrett Solar LLC | LU | 201 | NA | NA | NA |
| 2 | Gridforce Energy Management - GRID | SF | WSPP-1 | NA | NA | NA |
| 3 | Idaho Power Company | SF | WSPP-1 | NA | NA | NA |
| 4 | Labish Solar | LU | 201 | NA | NA | NA |
| 5 | Los Angeles Depart Water Power | SF | WSPP-1 | NA | NA | NA |
| 6 | Macquarie Cook Power | SF | WSPP-1 | NA | NA | NA |
| 7 | Morgan Stanley Capital Group | SF | PGE-11 | NA | NA | NA |
| 8 | Nevada Power Company | SF | WSPP-1 | NA | NA | NA |
| 9 | NextEra Energy Power Marketing, LLC | SF | WSPP-1 | NA | NA | NA |
| 10 | NextEra Energy Power Marketing, LLC | LF | WSPP-1 | NA | NA | NA |
| 11 | NorthWestern Corporation | SF | WSPP-1 | NA | NA | NA |
| 12 | NorthWestern Corporation | OS | WSPP-1 | NA | NA | NA |
| 13 | Northwestern Energy | SF | WSPP-1 | NA | NA | NA |
| 14 | Norwest Energy 14 | LU | 201 | NA | NA | NA |
| | Total | | | | | |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Obsidian Lakeview | LU | 201 | NA | NA | NA |
| 2 | OE Solar 3, LLC | LU | 201 | NA | NA | NA |
| 3 | Okanogan County PUD, Washington | SF | WSPP-1 | NA | NA | NA |
| 4 | Okanogan County PUD, Washington | LU | WSPP-1 | NA | NA | NA |
| 5 | Okanogan County PUD, Washington | LF | WSPP-1 | NA | NA | NA |
| 6 | O'Neil Solar | LU | 201 | NA | NA | NA |
| 7 | Outback Solar | LU | Outback | NA | NA | NA |
| 8 | Pacific Northwest Generating Company | SF | WSPP-1 | NA | NA | NA |
| 9 | PacifiCorp | SF | PGE-11 | NA | NA | NA |
| 10 | PaTu Wind | LU | WSPP-1 | NA | NA | NA |
| 11 | Duus Solar (Alchemy) | LU | 201 | NA | NA | NA |
| 12 | Portland, City of | LU | #2821 | NA | NA | NA |
| 13 | Powerex | SF | PGE-11 | NA | NA | NA |
| 14 | Grant County, PUD No. 2, Washington | LU | Wanapum | NA | NA | NA |
| | Total | | | | | |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Grant County, PUD No. 2, Washington | LU | Priest Rapids | NA | NA | NA |
| 2 | Grant County, PUD No. 2, Washington | SF | WSPP-1 | NA | NA | NA |
| 3 | Pend Orielle County PUD | SF | WSPP-1 | NA | NA | NA |
| 4 | Puget Sound Energy | SF | WSPP-1 | NA | NA | NA |
| 5 | Rafael Solar | LU | 201 | NA | NA | NA |
| 6 | Riley Solar | LU | 201 | NA | NA | NA |
| 7 | Rock Garden Solar | LU | 201 | NA | NA | NA |
| 8 | Sacramento Municipal Utility District | SF | WSPP-1 | NA | NA | NA |
| 9 | Seattle City Light | SF | WSPP-1 | NA | NA | NA |
| 10 | Shell Energy | SF | WSPP-1 | NA | NA | NA |
| 11 | Sheep Solar | LU | 201 | NA | NA | NA |
| 12 | Silverton Solar | LU | 201 | NA | NA | NA |
| 13 | Snohomish County, PUD No. 1, Washingn | SF | WSPP-1 | NA | NA | NA |
| 14 | SP Solar 1, LLC | LU | 201 | NA | NA | NA |
| | Total | | | | | |

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

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

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

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

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

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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 | SP Solar 5, LLC | LU | 201 | NA | NA | NA |
| 2 | SP Solar 6, LLC | LU | 201 | NA | NA | NA |
| 3 | SP Solar 7, LLC | LU | 201 | NA | NA | NA |
| 4 | SP Solar 8, LLC | LU | 201 | NA | NA | NA |
| 5 | Steel Bridge | LU | 201 | NA | NA | NA |
| 6 | Starvation Solar 1 LLC | LU | 201 | NA | NA | NA |
| 7 | St Louis Solar | LU | 201 | NA | NA | NA |
| 8 | Suluss Solar 35 | LU | 201 | NA | NA | NA |
| 9 | Suluss Solar 17 | LU | 201 | NA | NA | NA |
| 10 | Suntex Solar | LU | 201 | NA | NA | NA |
| 11 | West Hines Solar | LU | 201 | NA | NA | NA |
| 12 | Tacoma, City of | SF | WSPP-1 | NA | NA | NA |
| 13 | Tenaska Power Services | SF | WSPP-1 | NA | NA | NA |
| 14 | Tenaska Power Services | SF | WSPP-1 | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | // | End of 2020/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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|---|---|---|---|---|---|---|
| 1 | The Energy Authority | SF | WSPP-1 | NA | NA | NA |
| 2 | Thomas Creek Solar | LU | 201 | NA | NA | NA |
| 3 | Tickle Creek | LU | 201 | NA | NA | NA |
| 4 | TransAlta Energy Marketing | SF | PGE-11 | NA | NA | NA |
| 5 | TransCanada Energy Marketing | SF | WSPP-1 | NA | NA | NA |
| 6 | Tri-State Generation | SF | WSPP-1 | NA | NA | NA |
| 7 | Turlock Irrigation District | SF | WSPP-1 | NA | NA | NA |
| 8 | Vitol Inc. | SF | WSPP-1 | NA | NA | NA |
| 9 | Volcano Solar | LU | 201 | NA | NA | NA |
| 10 | VON FAMILY LTD PARTNERSHIP | LU | 201 | NA | NA | NA |
| 11 | Warm Springs Power Enterprises | LU | WSPP-1 | NA | NA | NA |
| 12 | Warm Springs Power Enterprises | LU | WSPP-1 | NA | NA | NA |
| 13 | Wheatridge Wind II, LLC | LU | WSPP-1 | NA | NA | NA |
| 14 | Kale Patch Solar | LU | 201 | NA | NA | NA |
| | Total | | | | | |

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

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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|---|---|---|---|---|---|---|
| 1 | Drift Creek | LU | 201 | NA | NA | NA |
| 2 | Yamhill Solar | LU | Yamhill | NA | NA | NA |
| 3 | Load Balance Energy | OS | OATT | NA | NA | NA |
| 4 | Country Village Estates | OS | 201 | NA | NA | NA |
| 5 | Domaine Drouhin | OS | 201 | NA | NA | NA |
| 6 | Lake Oswego Corporation | OS | 201 | NA | NA | NA |
| 7 | Minikahada Hydropower Co | OS | 201 | NA | NA | NA |
| 8 | Starbuck Properties | OS | 201 | NA | NA | NA |
| 9 | Solar Payment Option | OS | 215-217 | NA | NA | NA |
| 10 | Tualatin Valley Water Dist | OS | 201 | NA | NA | NA |
| 11 | Oregon Energy Fund | OS | 203 | NA | NA | NA |
| 12 | Green Power | | | NA | NA | NA |
| 13 | NVPC MONET QF Deferrals | | | NA | NA | NA |
| 14 | Margin on Electric Financials | | | NA | NA | NA |
| | Total | | | | | |

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

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

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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 | Load Curtailment Program | | | NA | NA | NA |
| 2 | Reserve Trading Credit Risk | | | NA | NA | NA |
| 3 | REC Retirement Expense | | | NA | NA | NA |
| 4 | Carbon Allowance Expense | | | NA | NA | NA |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES: MegaWatt Hours Received (h) | POWER EXCHANGES: MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER: Demand Charges ($) (j) | COST/SETTLEMENT OF POWER: Energy Charges ($) (k) | COST/SETTLEMENT OF POWER: Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| 20,000 | | | | 1,780,000 | | 1,780,000 | 1 |
| 103,807 | | | | 7,692,324 | | 7,692,324 | 2 |
| 16,919 | | | | 1,465,490 | | 1,465,490 | 3 |
| 487,362 | | | | 11,016,464 | | 11,016,464 | 4 |
| 187,312 | | | | 11,901,911 | | 11,901,911 | 5 |
| | | | 3,120,000 | | | 3,120,000 | 6 |
| 33,525 | | | | 1,635,752 | | 1,635,752 | 7 |
| 253,352 | | | | 2,644,274 | | 2,644,274 | 8 |
| 2,321 | | | | 337,685 | | 337,685 | 9 |
| 1,389 | | | | 202,853 | | 202,853 | 10 |
| 50 | | | | 2,000 | | 2,000 | 11 |
| 1,402,347 | | | | 19,067,944 | | 19,067,944 | 12 |
| 2,150 | | | | 345,007 | | 345,007 | 13 |
| 11,412 | | | | 151,690 | | 151,690 | 14 |
| 10,358,031 | | | 8,460,045 | 271,152,382 | 139,187,039 | 418,799,466 | |

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) | |
| 225 | | | | 9,450 | | 9,450 | 1 |
| 604,789 | | | | 7,862,237 | | 7,862,237 | 2 |
| 344,724 | | | | 7,583,924 | | 7,583,924 | 3 |
| | | | | 303,238 | | 303,238 | 4 |
| 104,910 | | | | 1,022,095 | | 1,022,095 | 5 |
| 159,559 | | | | 6,683,176 | | 6,683,176 | 6 |
| 800 | | | | 28,000 | | 28,000 | 7 |
| 4,337 | | | | 55,803 | | 55,803 | 8 |
| 1,308,557 | | | | 29,684,946 | | 29,684,946 | 9 |
| | | | | 71,696 | | 71,696 | 10 |
| 80,367 | | | | 1,484,843 | | 1,484,843 | 11 |
| 1,030,432 | | | | 23,330,563 | | 23,330,563 | 12 |
| | | | | 1,882,051 | | 1,882,051 | 13 |
| 7,865 | | | | 1,463,879 | | 1,463,879 | 14 |
| 10,358,031 | | | 8,460,045 | 271,152,382 | 139,187,039 | 418,799,466 | |

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| | | | 1,200,000 | | | 1,200,000 | 1 |
| 1,800 | | | | 8,050 | | 8,050 | 2 |
| 20,892 | | | | 1,723,515 | | 1,723,515 | 3 |
| 225 | | | | 9,750 | | 9,750 | 4 |
| 805 | | | | 28,597 | | 28,597 | 5 |
| 76,884 | | | | 5,589,811 | | 5,589,811 | 6 |
| | | | 84,000 | | | 84,000 | 7 |
| 23,923 | | | | 475,298 | | 475,298 | 8 |
| 46,910 | | | | 4,308,178 | | 4,308,178 | 9 |
| 67,938 | | | | 1,205,234 | | 1,205,234 | 10 |
| 16,428 | | | | 1,217,641 | | 1,217,641 | 11 |
| 22,747 | | | | 1,922,418 | | 1,922,418 | 12 |
| 16,424 | | | | 1,328,879 | | 1,328,879 | 13 |
| 20,602 | | | | | | | 14 |
| 10,358,031 | | | 8,460,045 | 271,152,382 | 139,187,039 | 418,799,466 | |

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| | | | | 58,711 | | 58,711 | 1 |
| 13 | | | | 458 | | 458 | 2 |
| 47,331 | | | | 571,748 | | 571,748 | 3 |
| 2,296 | | | | 282,387 | | 282,387 | 4 |
| 400 | | | | 13,800 | | 13,800 | 5 |
| 89,400 | | | | 1,372,799 | | 1,372,799 | 6 |
| 44,410 | | | | 873,999 | | 873,999 | 7 |
| 8,400 | | | | 361,200 | | 361,200 | 8 |
| 29,819 | | | | 84,653 | | 84,653 | 9 |
| 60,494 | | | | 1,303,306 | | 1,303,306 | 10 |
| 35,410 | | | | 188,339 | | 188,339 | 11 |
| -50,707 | | | | | | | 12 |
| 24 | | | | 433,904 | | 433,904 | 13 |
| 3,762 | | | | 380,681 | | 380,681 | 14 |
| 10,358,031 | | | 8,460,045 | 271,152,382 | 139,187,039 | 418,799,466 | |

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. |
|---|---|---|---|---|---|---|---|
| 23,837 | | | | 2,130,805 | | 2,130,805 | 1 |
| 25,020 | | | | 1,559,135 | | 1,559,135 | 2 |
| 5,084 | | | | 390,952 | | 390,952 | 3 |
| | | | 130,000 | | | 130,000 | 4 |
| | | | | 361,908 | | 361,908 | 5 |
| 2,192 | | | | 343,281 | | 343,281 | 6 |
| 10,368 | | | | 979,539 | | 979,539 | 7 |
| 65,096 | | | | 3,696,074 | | 3,696,074 | 8 |
| 36,179 | | | | 1,673,328 | | 1,673,328 | 9 |
| 32,515 | | | | 2,694,537 | | 2,694,537 | 10 |
| | | | | 3,228,264 | | 3,228,264 | 11 |
| 86,925 | | | | 2,355,819 | | 2,355,819 | 12 |
| 109,335 | | | | 3,593,694 | | 3,593,694 | 13 |
| 397,458 | | | | 11,946,035 | | 11,946,035 | 14 |
| 10,358,031 | | | 8,460,045 | 271,152,382 | 139,187,039 | 418,799,466 | |

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



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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 397,458 | | | | 11,946,035 | | 11,946,035 | 1 |
| 97,641 | | | | 2,674,143 | | 2,674,143 | 2 |
| 416,353 | | | | 10,650,395 | | 10,650,395 | 3 |
| 307,121 | | | | 7,141,340 | | 7,141,340 | 4 |
| 2,224 | | | | 309,816 | | 309,816 | 5 |
| 12,440 | | | | 1,059,150 | | 1,059,150 | 6 |
| 15,396 | | | | 1,330,053 | | 1,330,053 | 7 |
| 100 | | | | 3,650 | | 3,650 | 8 |
| 219,290 | | | | 5,557,298 | | 5,557,298 | 9 |
| 148,677 | | | | 2,403,750 | | 2,403,750 | 10 |
| 3,896 | | | | 348,720 | | 348,720 | 11 |
| 3,815 | | | | 335,141 | | 335,141 | 12 |
| 93,675 | | | | 1,356,257 | | 1,356,257 | 13 |
| 3,894 | | | | 351,801 | | 351,801 | 14 |
| 10,358,031 | | | 8,460,045 | 271,152,382 | 139,187,039 | 418,799,466 | |

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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| 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. |
|---|---|---|---|---|---|---|---|
| 3,946 | | | | 376,860 | | 376,860 | 1 |
| 3,064 | | | | 331,933 | | 331,933 | 2 |
| 3,064 | | | | 336,780 | | 336,780 | 3 |
| 3,894 | | | | 369,487 | | 369,487 | 4 |
| 3,292 | | | | 280,008 | | 280,008 | 5 |
| 25,743 | | | | 2,213,596 | | 2,213,596 | 6 |
| | | | | 269,190 | | 269,190 | 7 |
| | | | | 61,729 | | 61,729 | 8 |
| | | | | 72,549 | | 72,549 | 9 |
| 13,561 | | | | 1,175,491 | | 1,175,491 | 10 |
| 16,070 | | | | 1,391,218 | | 1,391,218 | 11 |
| 129,666 | | | | 2,230,475 | | 2,230,475 | 12 |
| 20,722 | | | | 808,573 | | 808,573 | 13 |
| | | | -73,955 | | | -73,955 | 14 |
| 10,358,031 | | | 8,460,045 | 271,152,382 | 139,187,039 | 418,799,466 | |

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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| 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. |
|---|---|---|---|---|---|---|---|
| 88,538 | | | | 1,369,805 | | 1,369,805 | 1 |
| 2,342 | | | | 282,807 | | 282,807 | 2 |
| 1,803 | | | | 198,629 | | 198,629 | 3 |
| 156,829 | | | | 3,140,935 | | 3,140,935 | 4 |
| 200 | | | | 11,335 | | 11,335 | 5 |
| 1 | | | | 24 | | 24 | 6 |
| 49,360 | | | | 429,652 | | 429,652 | 7 |
| 3,600 | | | | 71,300 | | 71,300 | 8 |
| 743 | | | | 94,226 | | 94,226 | 9 |
| 252 | | | | 13,176 | | 13,176 | 10 |
| 430,064 | | | | 9,257,607 | | 9,257,607 | 11 |
| | | | 4,000,000 | | | 4,000,000 | 12 |
| 43,059 | | | | 1,445,054 | | 1,445,054 | 13 |
| 2,328 | | | | 273,206 | | 273,206 | 14 |
| 10,358,031 | | | 8,460,045 | 271,152,382 | 139,187,039 | 418,799,466 | |

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) | |
| | | | | 390,029 | | 390,029 | 1 |
| 1,105 | | | | 62,170 | | 62,170 | 2 |
| 64,208 | | | | | | | 3 |
| | | | | 167 | | 167 | 4 |
| 103 | | | | 9,273 | | 9,273 | 5 |
| 180 | | | | 17,056 | | 17,056 | 6 |
| 143 | | | | 9,603 | | 9,603 | 7 |
| 18 | | | | 1,658 | | 1,658 | 8 |
| 18,719 | | | | 263,441 | | 263,441 | 9 |
| 284 | | | | 19,769 | | 19,769 | 10 |
| | | | | | 121,502 | 121,502 | 11 |
| | | | | | 16,225,182 | 16,225,182 | 12 |
| | | | | | 3,902,221 | 3,902,221 | 13 |
| | | | | | 122,228,935 | 122,228,935 | 14 |
| 10,358,031 | | | 8,460,045 | 271,152,382 | 139,187,039 | 418,799,466 | |

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) | |
| | | | | | -3,300 | -3,300 | 1 |
| | | | | | 38,098 | 38,098 | 2 |
| | | | | | 635,544 | 635,544 | 3 |
| | | | | | -3,961,143 | -3,961,143 | 4 |
| | | | | | | | 5 |
| | | | | | | | 6 |
| | | | | | | | 7 |
| | | | | | | | 8 |
| | | | | | | | 9 |
| | | | | | | | 10 |
| | | | | | | | 11 |
| | | | | | | | 12 |
| | | | | | | | 13 |
| | | | | | | | 14 |
| 10,358,031 | | | 8,460,045 | 271,152,382 | 139,187,039 | 418,799,466 | |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

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

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

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

The 2020 Douglas County contract expires on 12/31/2025.

***Schedule Page: 326.3 Line No.: 10 Column: b***

The NextEra contract expires on 12/3/2050

***Schedule Page: 326.3 Line No.: 12 Column: b***

Colstrip Nonrunning Loss (station services)

***Schedule Page: 326.4 Line No.: 5 Column: b***

The 2020 Okanogan County contract expires on 12/31/2025.

***Schedule Page: 326.8 Line No.: 3 Column: a***

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

***Schedule Page: 326.8 Line No.: 4 Column: b***

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

***Schedule Page: 326.8 Line No.: 5 Column: b***

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

***Schedule Page: 326.8 Line No.: 6 Column: b***

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

***Schedule Page: 326.8 Line No.: 7 Column: b***

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

***Schedule Page: 326.8 Line No.: 8 Column: b***

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

***Schedule Page: 326.8 Line No.: 9 Column: b***

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

***Schedule Page: 326.8 Line No.: 10 Column: b***

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

***Schedule Page: 326.8 Line No.: 11 Column: b***

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

***Schedule Page: 326.8 Line No.: 12 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: 326.8 Line No.: 13 Column: l***

2020 NVPC MONET QF Deferrals & Cure Payments

***Schedule Page: 326.8 Line No.: 14 Column: l***

Margin on electric financial transactions.

***Schedule Page: 326.9 Line No.: 1 Column: l***

Load Curtailment Program.

***Schedule Page: 326.9 Line No.: 2 Column: l***

Reserve for trading credit risk.

***Schedule Page: 326.9 Line No.: 3 Column: l***

Expense of annual REC retirement to meet RPS compliance.

***Schedule Page: 326.9 Line No.: 4 Column: l***

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

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

## 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 | BPA Power Business Line | Bonneville Power Administration | West Oregon Electric Coop Total | OLF |
| 2 | BPA Power Business Line | Bonneville Power Administration | Other TVI Pumps Total | OLF |
| 3 | BPA Power Business Line | Bonneville Power Administration | Canby PUD Total | OLF |
| 4 | BPA Power Business Line | Bonneville Power Administration | Columbia River PUD Total | OLF |
| 5 | Pacificorp West | PacifiCorp | Portland General Electric | OLF |
| 6 | 3 Phases Renewables LLC | Bonneville Power Administration | Oregon Direct Access | FNO |
| 7 | Avangrid Renewables, LLC | Bonneville Power Administration | Oregon Direct Access | FNO |
| 8 | BPA Power Business Line | Bonneville Power Administration | Portland General Electric | FNO |
| 9 | BPA Power Business Line | | | OS |
| 10 | Calpine Energy Services | Bonneville Power Administration | Oregon Direct Access | FNO |
| 11 | Constellation New Energy | Bonneville Power Administration | Oregon Direct Access | FNO |
| 12 | Shell Energy North America | Bonneville Power Administration | Oregon Direct Access | FNO |
| 13 | Avista Corp | Bonneville Power Administration | Balancing Authority of Northern C | LFP |
| 14 | Avista Corp | Bonneville Power Administration | California Independent System Ope | LFP |
| 15 | Avista Corp | California Independent System Ope | Bonneville Power Administration | NF |
| 16 | Avista Corp | California Independent System Ope | Bonneville Power Administration | OS |
| 17 | Avista Corp | | | OS |
| 18 | BPA Power Business Line | Bonneville Power Administration | California Independent System Ope | NF |
| 19 | Brookfield Renewable Trading and Marketing | Bonneville Power Administration | California Independent System Ope | NF |
| 20 | Brookfield Renewable Trading and Marketing | | | OS |
| 21 | Shell Energy North America | Bonneville Power Administration | Balancing Authority of Northern C | LFP |
| 22 | Shell Energy North America | Bonneville Power Administration | California Independent System Ope | LFP |
| 23 | Shell Energy North America | Bonneville Power Administration | California Independent System Ope | LFP |
| 24 | Shell Energy North America | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 25 | Shell Energy North America | Bonneville Power Administration | California Independent System Ope | NF |
| 26 | Shell Energy North America | Bonneville Power Administration | Portland General Electric | NF |
| 27 | Shell Energy North America | California Independent System Ope | Bonneville Power Administration | OS |
| 28 | Shell Energy North America | | | OS |
| 29 | Constellation New Energy | Bonneville Power Administration | California Independent System Ope | LFP |
| 30 | Constellation New Energy | Bonneville Power Administration | Balancing Authority of Northern C | LFP |
| 31 | Constellation New Energy | Bonneville Power Administration | Portland General Electric | LFP |
| 32 | Constellation New Energy | Bonneville Power Administration | California Independent System Ope | NF |
| 33 | Constellation New Energy | | | OS |
| 34 | Macquarie Energy LLC | Bonneville Power Administration | California Independent System Ope | NF |
| | **TOTAL** | | | |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr) | Year/Period of Report<br>End of 2020/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 | Macquarie Energy LLC | | | OS |
| 2 | Morgan Stanley Capital Group | Bonneville Power Administration | Balancing Authority of Northern C | LFP |
| 3 | Morgan Stanley Capital Group | Bonneville Power Administration | California Independent System Ope | LFP |
| 4 | Morgan Stanley Capital Group | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 5 | Morgan Stanley Capital Group | Bonneville Power Administration | California Independent System Ope | NF |
| 6 | Morgan Stanley Capital Group | California Independent System Ope | Bonneville Power Administration | NF |
| 7 | Morgan Stanley Capital Group | California Independent System Ope | Bonneville Power Administration | OS |
| 8 | Morgan Stanley Capital Group | | | OS |
| 9 | Pacificorp West | Portland General Electric | Bonneville Power Administration | LFP |
| 10 | Pacificorp West | Portland General Electric | Bonneville Power Administration | NF |
| 11 | Pacificorp West | | | OS |
| 12 | Avangrid Renewables, LLC | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 13 | Avangrid Renewables, LLC | Bonneville Power Administration | California Independent System Ope | NF |
| 14 | Avangrid Renewables, LLC | Bonneville Power Administration | Bonneville Power Administration | NF |
| 15 | Avangrid Renewables, LLC | | | OS |
| 16 | Puget Sound Energy | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 17 | Puget Sound Energy | Bonneville Power Administration | California Independent System Ope | NF |
| 18 | Puget Sound Energy | | | OS |
| 19 | Powerex Inc. | Bonneville Power Administration | Balancing Authority of Northern C | LFP |
| 20 | Powerex Inc. | Bonneville Power Administration | California Independent System Ope | LFP |
| 21 | Powerex Inc. | California Independent System Ope | Bonneville Power Administration | LFP |
| 22 | Powerex Inc. | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 23 | Powerex Inc. | Bonneville Power Administration | California Independent System Ope | NF |
| 24 | Powerex Inc. | California Independent System Ope | Bonneville Power Administration | NF |
| 25 | Powerex Inc. | California Independent System Ope | Bonneville Power Administration | OS |
| 26 | Powerex Inc. | | | OS |
| 27 | Seattle City Light | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 28 | Seattle City Light | | | OS |
| 29 | The Energy Authority | Bonneville Power Administration | Balancing Authority of Northern C | LFP |
| 30 | The Energy Authority | Bonneville Power Administration | California Independent System Ope | LFP |
| 31 | The Energy Authority | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 32 | The Energy Authority | Bonneville Power Administration | California Independent System Ope | NF |
| 33 | The Energy Authority | California Independent System Ope | Bonneville Power Administration | NF |
| 34 | The Energy Authority | California Independent System Ope | Bonneville Power Administration | OS |
| | **TOTAL** | | | |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2020/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 | The Energy Authority | | | OS |
| 2 | Transalta Energy Marketing (US) Inc. | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 3 | Transalta Energy Marketing (US) Inc. | Bonneville Power Administration | California Independent System Ope | NF |
| 4 | Transalta Energy Marketing (US) Inc. | California Independent System Ope | Bonneville Power Administration | NF |
| 5 | Transalta Energy Marketing (US) Inc. | | | OS |
| 6 | Turlock Irrigation District | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 7 | Turlock Irrigation District | | | OS |
| 8 | Tacoma Power | Bonneville Power Administration | California Independent System Ope | NF |
| 9 | Tacoma Power | | | OS |
| 10 | Public Utility District No. 1 of Cowlitz Count | Bonneville Power Administration | California Independent System Ope | LFP |
| 11 | Public Utility District No. 1 of Franklin Coun | Bonneville Power Administration | California Independent System Ope | LFP |
| 12 | Public Utility District No. 1 of Klickitat Cou | Bonneville Power Administration | California Independent System Ope | LFP |
| 13 | Public Utility District No. 1 of Lewis County | Bonneville Power Administration | California Independent System Ope | LFP |
| 14 | Accrual | | | AD |
| 15 | | | | |
| 16 | | | | |
| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | | | | |
| 21 | | | | |
| 22 | | | | |
| 23 | | | | |
| 24 | | | | |
| 25 | | | | |
| 26 | | | | |
| 27 | | | | |
| 28 | | | | |
| 29 | | | | |
| 30 | | | | |
| 31 | | | | |
| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
| | **TOTAL** | | | |

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

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

| FERC Rate Schedule of Tariff Number (e) | Point of Receipt (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY MegaWatt Hours Received (i) | MegaWatt Hours Delivered (j) | Line No. |
|---|---|---|---|---|---|---|
| 72 | BPAT.PGE | Various | | 13,196 | 13,078 | 1 |
| 72 | BPAT.PGE | Various | | 6,824 | 6,763 | 2 |
| 72 | BPAT.PGE | Various | | 185,208 | 183,558 | 3 |
| 72 | BPAT.PGE | Various | | 171,171 | 169,647 | 4 |
| Exchange | PACW.PGE | Various | | 3,901 | 3,908 | 5 |
| 7 | BPAT.PGE | Various | 15 | 8,783 | 8,783 | 6 |
| 7 | BPAT.PGE | Various | 300 | 114,163 | 114,163 | 7 |
| 7 | BPAT.PGE | Various Subs | 126 | 78,372 | 78,372 | 8 |
| 11 | | | | | | 9 |
| 7 | BPAT.PGE | Various | 2,512 | 1,455,353 | 1,455,353 | 10 |
| 7 | BPAT.PGE | Various | 922 | 461,202 | 461,202 | 11 |
| 7 | BPAT.PGE | Various | 375 | 225,983 | 225,983 | 12 |
| 7 | JohnDay | CaptainJack | | 5,571 | 5,571 | 13 |
| 7 | JohnDay | Malin500 | | 382,944 | 382,944 | 14 |
| 8 | Malin500 | JohnDay | | 200 | 200 | 15 |
| 8 | Malin500 | JohnDay | | 525 | 525 | 16 |
| 11 | | | | | | 17 |
| 8 | JohnDay | Malin500 | | 97 | 97 | 18 |
| 8 | JohnDay | Malin500 | | 2,125 | 2,125 | 19 |
| 11 | | | | | | 20 |
| 7 | JohnDay | CaptainJack | | 538,656 | 538,656 | 21 |
| 7 | JohnDay | COBH | | 188 | 188 | 22 |
| 7 | JohnDay | Malin500 | | 766,582 | 766,582 | 23 |
| 8 | JohnDay | CaptainJack | | 9,417 | 9,417 | 24 |
| 8 | JohnDay | Malin500 | | 59,294 | 59,294 | 25 |
| 8 | BPAT.PGE | PGE | | 32 | 32 | 26 |
| 8 | Malin500 | JohnDay | | 923 | 923 | 27 |
| 11 | | | | | | 28 |
| 7 | JohnDay | Malin500 | | 70,012 | 70,012 | 29 |
| 7 | JohnDay | CaptainJack | | 474 | 474 | 30 |
| 7 | BPAT.PGE | PGE | | 64 | 64 | 31 |
| 8 | JohnDay | Malin500 | | 1,157 | 1,157 | 32 |
| 11 | | | | | | 33 |
| 8 | JohnDay | Malin500 | | 323 | 323 | 34 |
| | | | **4,250** | **6,818,609** | **6,815,263** | |

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

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

| FERC Rate Schedule of Tariff Number (e) | Point of Receipt (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY MegaWatt Hours Received (i) | MegaWatt Hours Delivered (j) | Line No. |
| --- | --- | --- | --- | --- | --- | --- |
| 11 | | | | | | 1 |
| 7 | JohnDay | CaptainJack | | 123,807 | 123,807 | 2 |
| 7 | JohnDay | Malin500 | | 58,000 | 58,000 | 3 |
| 8 | JohnDay | CaptainJack | | 7,364 | 7,364 | 4 |
| 8 | JohnDay | Malin500 | | 7,580 | 7,580 | 5 |
| 8 | Malin500 | JohnDay | | 30 | 30 | 6 |
| 8 | Malin500 | JohnDay | | 34 | 34 | 7 |
| 11 | | | | | | 8 |
| 7 | RoundButte | REDMOND | | 15,190 | 15,190 | 9 |
| 8 | RoundButte | REDMOND | | 883 | 883 | 10 |
| 11 | | | | | | 11 |
| 8 | JohnDay | CaptainJack | | 11 | 11 | 12 |
| 8 | JohnDay | Malin500 | | 113 | 113 | 13 |
| 8 | KFallsGen | JohnDay | | 839 | 839 | 14 |
| 11 | | | | | | 15 |
| 8 | JohnDay | CaptainJack | | 141 | 141 | 16 |
| 8 | JohnDay | Malin500 | | 332 | 332 | 17 |
| 11 | | | | | | 18 |
| 7 | JohnDay | CaptainJack | | 94,021 | 94,021 | 19 |
| 7 | JohnDay | Malin500 | | 1,482,919 | 1,482,919 | 20 |
| 7 | Malin500 | JohnDay | | 208,347 | 208,347 | 21 |
| 8 | JohnDay | CaptainJack | | 2,355 | 2,355 | 22 |
| 8 | JohnDay | Malin500 | | 3,234 | 3,234 | 23 |
| 8 | Malin500 | JohnDay | | 1,951 | 1,951 | 24 |
| 8 | Malin500 | JohnDay | | 25 | 25 | 25 |
| 11 | | | | | | 26 |
| 8 | JohnDay | CaptainJack | | 669 | 669 | 27 |
| 11 | | | | | | 28 |
| 7 | JohnDay | CaptainJack | | 37,725 | 37,725 | 29 |
| 7 | JohnDay | Malin500 | | 186,488 | 186,488 | 30 |
| 8 | JohnDay | CaptainJack | | 1,771 | 1,771 | 31 |
| 8 | JohnDay | Malin500 | | 3,646 | 3,646 | 32 |
| 8 | Malin500 | JohnDay | | 1,848 | 1,848 | 33 |
| 8 | Malin500 | JohnDay | | 329 | 329 | 34 |
| | | | **4,250** | **6,818,609** | **6,815,263** | |

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. |
|---|---|---|---|---|---|---|
| 11 | | | | | | 1 |
| 8 | JohnDay | CaptainJack | | 3,264 | 3,264 | 2 |
| 8 | JohnDay | Malin500 | | 12,122 | 12,122 | 3 |
| 8 | Malin500 | JohnDay | | 743 | 743 | 4 |
| 11 | | | | | | 5 |
| 8 | JohnDay | CaptainJack | | 87 | 87 | 6 |
| 11 | | | | | | 7 |
| 8 | JohnDay | Malin500 | | 1 | 1 | 8 |
| 11 | | | | | | 9 |
| 7 | JohnDay | COBH | | | | 10 |
| 7 | JohnDay | COBH | | | | 11 |
| 7 | JohnDay | COBH | | | | 12 |
| 7 | JohnDay | COBH | | | | 13 |
| | | | | | | 14 |
| | | | | | | 15 |
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| | | | | | | 31 |
| | | | | | | 32 |
| | | | | | | 33 |
| | | | | | | 34 |
| | | | **4,250** | **6,818,609** | **6,815,263** | |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr) | Year/Period of Report<br>End of 2020/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. |
|---|---|---|---|---|
| | | 90,848 | 90,848 | 1 |
| | | 26,249 | 26,249 | 2 |
| | | 368,928 | 368,928 | 3 |
| | | 24,853 | 24,853 | 4 |
| | | 247,328 | 247,328 | 5 |
| 5,763 | -93,160 | 4,079 | -83,318 | 6 |
| 113,938 | 62,013 | 72,323 | 248,274 | 7 |
| 33,130 | -160,280 | 51,833 | -75,317 | 8 |
| | 27,586 | | 27,586 | 9 |
| 954,407 | -76,064 | 693,237 | 1,571,580 | 10 |
| 350,548 | 289,640 | 220,961 | 861,149 | 11 |
| 142,639 | -971,012 | 107,370 | -721,004 | 12 |
| | | 9,220 | 9,220 | 13 |
| | | 633,769 | 633,769 | 14 |
| | | 255 | 255 | 15 |
| | | | | 16 |
| | 163,580 | | 163,580 | 17 |
| | | 151 | 151 | 18 |
| | | 3,496 | 3,496 | 19 |
| | 840 | | 840 | 20 |
| | | 530,631 | 530,631 | 21 |
| | | 185 | 185 | 22 |
| | | 755,162 | 755,162 | 23 |
| | | 13,551 | 13,551 | 24 |
| | | 85,322 | 85,322 | 25 |
| | | 46 | 46 | 26 |
| | | | | 27 |
| | 559,884 | | 559,884 | 28 |
| | | 63,965 | 63,965 | 29 |
| | | 433 | 433 | 30 |
| | | 58 | 58 | 31 |
| | | 931 | 931 | 32 |
| | 30,760 | | 30,760 | 33 |
| | | 656 | 656 | 34 |
| **1,600,425** | **897,657** | **7,243,989** | **9,742,070** | |

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. |
|---|---|---|---|---|
| | 123 | | 123 | 1 |
| | | 156,557 | 156,557 | 2 |
| | | 73,342 | 73,342 | 3 |
| | | 12,747 | 12,747 | 4 |
| | | 13,121 | 13,121 | 5 |
| | | 52 | 52 | 6 |
| | | | | 7 |
| | 84,903 | | 84,903 | 8 |
| | | 85,354 | 85,354 | 9 |
| | | 1,806 | 1,806 | 10 |
| | 4,326 | | 4,326 | 11 |
| | | 11 | 11 | 12 |
| | | 116 | 116 | 13 |
| | | 862 | 862 | 14 |
| | 373 | | 373 | 15 |
| | | 109 | 109 | 16 |
| | | 258 | 258 | 17 |
| | 122 | | 122 | 18 |
| | | 129,355 | 129,355 | 19 |
| | | 2,040,217 | 2,040,217 | 20 |
| | | 286,646 | 286,646 | 21 |
| | | 7,364 | 7,364 | 22 |
| | | 10,113 | 10,113 | 23 |
| | | 6,101 | 6,101 | 24 |
| | | | | 25 |
| | 781,846 | | 781,846 | 26 |
| | | 800 | 800 | 27 |
| | 381 | | 381 | 28 |
| | | 10,819 | 10,819 | 29 |
| | | 53,480 | 53,480 | 30 |
| | | 2,340 | 2,340 | 31 |
| | | 4,816 | 4,816 | 32 |
| | | 2,441 | 2,441 | 33 |
| | | | | 34 |
| **1,600,425** | **897,657** | **7,243,989** | **9,742,070** | |

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. |
|---|---|---|---|---|
| | 98,372 | | 98,372 | 1 |
| | | 4,666 | 4,666 | 2 |
| | | 17,328 | 17,328 | 3 |
| | | 1,062 | 1,062 | 4 |
| | 7,763 | | 7,763 | 5 |
| | | 115 | 115 | 6 |
| | 34 | | 34 | 7 |
| | | 1 | 1 | 8 |
| | | | | 9 |
| | | 64,299 | 64,299 | 10 |
| | | 64,299 | 64,299 | 11 |
| | | 70,729 | 70,729 | 12 |
| | | 70,729 | 70,729 | 13 |
| | 85,627 | 46,094 | 131,721 | 14 |
| | | | | 15 |
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| | | | | 33 |
| | | | | 34 |
| **1,600,425** | **897,657** | **7,243,989** | **9,742,070** | |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

***Schedule Page: 328 Line No.: 1 Column: d***
Contract with Bonneville Power Administration continues until terminated.

***Schedule Page: 328 Line No.: 1 Column: m***
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PGE and the Bonneville Power Administration, Rate Schedule 72. The contract is evergreen.

***Schedule Page: 328 Line No.: 2 Column: d***
Contract with Bonneville Power Administration continues until terminated.

***Schedule Page: 328 Line No.: 2 Column: m***
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PGE and the Bonneville Power Administration, Rate Schedule 72. The contract is evergreen.

***Schedule Page: 328 Line No.: 3 Column: d***
Contract with Bonneville Power Administration continues until terminated.

***Schedule Page: 328 Line No.: 3 Column: m***
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PGE and the Bonneville Power Administration, Rate Schedule 72. The contract is evergreen.

***Schedule Page: 328 Line No.: 4 Column: d***
Contract with Bonneville Power Administration continues until terminated.

***Schedule Page: 328 Line No.: 4 Column: m***
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PGE and the Bonneville Power Administration, Rate Schedule 72. The contract is evergreen.

***Schedule Page: 328 Line No.: 5 Column: d***
Exchange agreement with PacifiCorp.

***Schedule Page: 328 Line No.: 5 Column: m***
Pre-888 contract executed between PGE and the PacifiCorp concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PGE and the PacifiCorp, Exchange Agreement).

***Schedule Page: 328 Line No.: 6 Column: l***
Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4r of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.

***Schedule Page: 328 Line No.: 6 Column: m***
Includes Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

***Schedule Page: 328 Line No.: 7 Column: l***
Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4r of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.

***Schedule Page: 328 Line No.: 7 Column: m***
Includes Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

***Schedule Page: 328 Line No.: 8 Column: l***
Charges or credits resulting from the provision of Energy Imbalance Service in accordance

with Schedule 4 and Schedule 4r of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.

***Schedule Page: 328 Line No.: 8 Column: m***

Includes Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

***Schedule Page: 328 Line No.: 10 Column: l***

Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4r of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.

***Schedule Page: 328 Line No.: 10 Column: m***

Includes Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

***Schedule Page: 328 Line No.: 11 Column: l***

Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4r of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.

***Schedule Page: 328 Line No.: 11 Column: m***

Includes Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

***Schedule Page: 328 Line No.: 12 Column: l***

Charges or credits resulting from the provision of Energy Imbalance Service in accordance with Schedule 4 and Schedule 4r of PGE's Open Access Transmission Tariff (OATT) for the current quarter. PGE provides Energy Imbalance Service through the Western Energy Imbalance Market operated by the California Independent System Operator. Charges or credits reflect most current statement from the market operator.

***Schedule Page: 328 Line No.: 12 Column: m***

Includes Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

***Schedule Page: 328 Line No.: 13 Column: d***

Contract with Avista Corp expires on 01/01/2023.

***Schedule Page: 328 Line No.: 13 Column: m***

Includes Scheduling, system control and dispatch service.

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

Contract with Avista Corp expires on 01/01/2023.

***Schedule Page: 328 Line No.: 14 Column: m***

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328 Line No.: 15 Column: m***

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328 Line No.: 16 Column: d***

Represents non-billed redirected MWHs.

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

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.

***Schedule Page: 328 Line No.: 18 Column: m***

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328 Line No.: 19 Column: m***

Includes Scheduling, system control and dispatch service.

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

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.

**Schedule Page: 328 Line No.: 21 Column: d**

Contract with Shell Energy North America (US) LP expires 12/31/2021.

**Schedule Page: 328 Line No.: 21 Column: m**

Includes Scheduling, system control and dispatch service.

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

Contract with Shell Energy North America (US) LP expires 12/31/2021.

**Schedule Page: 328 Line No.: 22 Column: m**

Includes Scheduling, system control and dispatch service.

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

Contract with Shell Energy North America (US) LP expires 12/31/2021.

**Schedule Page: 328 Line No.: 23 Column: m**

Includes Scheduling, system control and dispatch service.

**Schedule Page: 328 Line No.: 24 Column: m**

Includes Scheduling, system control and dispatch service.

**Schedule Page: 328 Line No.: 25 Column: m**

Includes Scheduling, system control and dispatch service.

**Schedule Page: 328 Line No.: 26 Column: m**

Includes Scheduling, system control and dispatch service.

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

Represents non-billed redirected MWHs.

**Schedule Page: 328 Line No.: 28 Column: d**

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.

**Schedule Page: 328 Line No.: 29 Column: d**

Contract with Constellation New Energy expires 01/01/2034.

**Schedule Page: 328 Line No.: 29 Column: m**

Includes Scheduling, system control and dispatch service.

**Schedule Page: 328 Line No.: 30 Column: d**

Contract with Constellation New Energy expires 01/01/2034.

**Schedule Page: 328 Line No.: 30 Column: m**

Includes Scheduling, system control and dispatch service.

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

Contract with Constellation New Energy expires 01/01/2034.

**Schedule Page: 328 Line No.: 31 Column: m**

Includes Scheduling, system control and dispatch service.

**Schedule Page: 328 Line No.: 32 Column: m**

Includes Scheduling, system control and dispatch service.

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

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.

**Schedule Page: 328 Line No.: 34 Column: m**

Includes Scheduling, system control and dispatch service.

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

Contract with Morgan Stanley Capital Group Inc expires 01/01/2034.

**Schedule Page: 328.1 Line No.: 2 Column: m**

Includes Scheduling, system control and dispatch service.

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

Contract with Morgan Stanley Capital Group Inc expires 01/01/2034.

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

***Schedule Page: 328.1 Line No.: 3 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 4 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 5 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 6 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 7 Column: d***
Represents non-billed redirected MWHs.
***Schedule Page: 328.1 Line No.: 8 Column: d***
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
***Schedule Page: 328.1 Line No.: 9 Column: d***
Contract with PacifiCorp expires 04/01/2022.
***Schedule Page: 328.1 Line No.: 9 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 10 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 11 Column: d***
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
***Schedule Page: 328.1 Line No.: 12 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 13 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 14 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 15 Column: d***
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
***Schedule Page: 328.1 Line No.: 16 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 17 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 18 Column: d***
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
***Schedule Page: 328.1 Line No.: 19 Column: d***
Contract with PowerEx expires 01/01/2022.
***Schedule Page: 328.1 Line No.: 19 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 20 Column: d***
Contract with PowerEx expires 01/01/2022.
***Schedule Page: 328.1 Line No.: 20 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 21 Column: d***
Contract with PowerEx expires 01/01/2022.
***Schedule Page: 328.1 Line No.: 21 Column: m***
Includes Scheduling, system control and dispatch service.
***Schedule Page: 328.1 Line No.: 22 Column: m***

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328.1 Line No.: 23 Column: m***

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328.1 Line No.: 24 Column: m***

Includes Scheduling, system control and dispatch service.

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

Represents non-billed redirected MWHs.

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

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.

***Schedule Page: 328.1 Line No.: 27 Column: m***

Includes Scheduling, system control and dispatch service.

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

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.

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

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

***Schedule Page: 328.1 Line No.: 29 Column: m***

Includes Scheduling, system control and dispatch service.

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

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

***Schedule Page: 328.1 Line No.: 30 Column: m***

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328.1 Line No.: 31 Column: m***

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328.1 Line No.: 32 Column: m***

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328.1 Line No.: 33 Column: m***

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328.1 Line No.: 34 Column: d***

Represents non-billed redirected MWHs.

***Schedule Page: 328.2 Line No.: 1 Column: d***

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.

***Schedule Page: 328.2 Line No.: 2 Column: m***

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328.2 Line No.: 3 Column: m***

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328.2 Line No.: 4 Column: m***

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328.2 Line No.: 5 Column: d***

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.

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

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328.2 Line No.: 7 Column: d***

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.

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

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Sections 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.

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

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

***Schedule Page: 328.2 Line No.: 10 Column: m***

Includes Scheduling, system control and dispatch service.

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

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

***Schedule Page: 328.2 Line No.: 11 Column: m***

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328.2 Line No.: 12 Column: d***

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

***Schedule Page: 328.2 Line No.: 12 Column: m***

Includes Scheduling, system control and dispatch service.

***Schedule Page: 328.2 Line No.: 13 Column: d***

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

***Schedule Page: 328.2 Line No.: 13 Column: m***

Includes Scheduling, system control and dispatch service.

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

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

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2020/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 | | | | | |
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| 3 | | | | | |
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| 34 | | | | | |
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| 36 | | | | | |
| 37 | | | | | |
| 38 | | | | | |
| 39 | | | | | |
| 40 | TOTAL | | | | |

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | TRANSFER OF ENERGY Magawatt-hours Received (c) | Magawatt-hours Delivered (d) | EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e) | Energy Charges ($) (f) | Other Charges ($) (g) | Total Cost of Transmission ($) (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | Bonneville Power Admin | LFP | | | 66,511,983 | | | 66,511,983 |
| 2 | Bonneville Power Admin | OS | 171,548 | 171,548 | | | 14,862,921 | 14,862,921 |
| 3 | Bonneville Power Admin | SFP | 5,101 | 5,101 | | 48,218 | | 48,218 |
| 4 | Bonneville Power Admin | NF | 3,442 | 3,442 | | 32,639 | | 32,639 |
| 5 | Bonneville Power Admin | AD | | | | | -201,188 | -201,188 |
| 6 | Avista Corp | NF | 7,777 | 7,777 | | 44,873 | | 44,873 |
| 7 | Calpine Energy Services | LFP | 18,700 | 18,700 | | 51,900 | | 51,900 |
| 8 | Columbia River PUD | SFP | 13 | 13 | | 19,032 | | 19,032 |
| 9 | DET - Gamesa | OS | | | | | -1,749,543 | -1,749,543 |
| 10 | EDF Renewable N.America | OS | | | | | -1,500,000 | -1,500,000 |
| 11 | Eugene Water & Electric | LFP | 23 | 23 | | 110,352 | | 110,352 |
| 12 | Idaho Power Company | NF | 8,400 | 8,400 | | 41,272 | | 41,272 |
| 13 | McMinnville Water & Lig | LFP | 916 | 916 | | 9,429 | | 9,429 |
| 14 | Montana, State of | OS | | | | | 2,156,041 | 2,156,041 |
| 15 | MACQUARIE ENERGY LLC | NF | 2 | 2 | | 9,200 | | 9,200 |
| 16 | Morgan Stanley | NF | 110,400 | 110,400 | | 165,600 | | 165,600 |
| | TOTAL | | 608,517 | 608,517 | 66,511,983 | 1,109,363 | 13,658,822 | 81,280,168 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2020/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 | NorthWestern Energy | NF | 41,173 | 41,173 | | 267,511 | | 267,511 |
| 2 | PacifiCorp | OS | | | | | 90,591 | 90,591 |
| 3 | PacifiCorp | SFP | 82,960 | 82,960 | | 62,721 | | 62,721 |
| 4 | Puget Sound Energy | NF | 156,912 | 156,912 | | 244,928 | | 244,928 |
| 5 | Seattle City Light | NF | 1,150 | 1,150 | | 1,688 | | 1,688 |
| 6 | | | | | | | | |
| 7 | | | | | | | | |
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| 14 | | | | | | | | |
| 15 | | | | | | | | |
| 16 | | | | | | | | |
| | TOTAL | | 608,517 | 608,517 | 66,511,983 | 1,109,363 | 13,658,822 | 81,280,168 |

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

***Schedule Page: 332     Line No.: 1     Column: b***

Represents Bonneville Power Administration PTP contracts that have termination dates that range from 10/1/2020 - 1/1/2030.

***Schedule Page: 332     Line No.: 2     Column: g***

Represents Bonneville Power Administration Ancillary Transmission Services.

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

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

***Schedule Page: 332     Line No.: 9     Column: g***

Represents reduction in transmission expense from PGE assumption of DET long-term PTP transmission capacity.

***Schedule Page: 332     Line No.: 10     Column: g***

Represents reduction in transmission expense from PGE assumption of EDF long-term PTP transmission capacity.

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

Represents Eugene Water & Electric Board contract which terminates on 12/1/2023.

***Schedule Page: 332     Line No.: 13     Column: b***

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

***Schedule Page: 332     Line No.: 14     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: 332.1     Line No.: 2     Column: g***

Represents PacifiCorp's Linneman Transmission Services.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

| Line No. | Description (a) | Amount (b) |
|---|---|---|
| 1 | Industry Association Dues | 2,387,303 |
| 2 | Nuclear Power Research Expenses | |
| 3 | Other Experimental and General Research Expenses | 2,475,704 |
| 4 | Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities | 2,283,192 |
| 5 | Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000 | |
| 6 | Involuntary Severance | 8,394,117 |
| 7 | Directors Pension | 160,032 |
| 8 | Directors Fees and Expenses | 460,220 |
| 9 | Directors and Officers Expenses | 2,334,299 |
| 10 | Misc. Admin expenses | 251,139 |
| 11 | Colstrip - PPL Montana | 1,974,140 |
| 12 | | |
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| 43 | | |
| 44 | | |
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| 46 | TOTAL | 20,720,146 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | // | End of 2020/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<br>(a) | Depreciation Expense (Account 403)<br>(b) | Depreciation Expense for Asset Retirement Costs (Account 403.1)<br>(c) | Amortization of Limited Term Electric Plant (Account 404)<br>(d) | Amortization of Other Electric Plant (Acc 405)<br>(e) | Total<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Intangible Plant | | | 64,345,245 | | 64,345,245 |
| 2 | Steam Production Plant | 35,635,281 | -4,755,833 | | | 30,879,448 |
| 3 | Nuclear Production Plant | | | | | |
| 4 | Hydraulic Production Plant-Conventional | 22,253,338 | 69 | | | 22,253,407 |
| 5 | Hydraulic Production Plant-Pumped Storage | | | | | |
| 6 | Other Production Plant | 77,911,218 | 783,863 | | | 78,695,081 |
| 7 | Transmission Plant | 17,911,508 | 1 | | | 17,911,509 |
| 8 | Distribution Plant | 120,963,563 | 5,528 | | | 120,969,091 |
| 9 | Regional Transmission and Market Operation | | | | | |
| 10 | General Plant | 40,658,204 | 99 | | | 40,658,303 |
| 11 | Common Plant-Electric | | | | | |
| 12 | TOTAL | 315,333,112 | -3,966,273 | 64,345,245 | | 375,712,084 |

### B. Basis for Amortization Charges

Five year and ten year amortization of computer software.

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

Thirty, forty and fifty amortization of hydro licensing costs.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | Applied depreciation | | | | | | |
| 13 | rates for all assets | | | | | | |
| 14 | effective 1/1/2018 per | | | | | | |
| 15 | Order 17-365 in | | | | | | |
| 16 | OPUC Docket UM-1809 | | | | | | |
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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 | | 283,706 | 283,706 | |
| 2 | Docket RM06-16 | | | | |
| 3 | | | | | |
| 4 | FERC-NERC Reliability | | 118,110 | 118,110 | |
| 5 | Docket RM06-22 | | | | |
| 6 | | | | | |
| 7 | FERC matters less than $25,000 | | 10,565 | 10,565 | |
| 8 | | | | | |
| 9 | OPUC Docket UM 1631 | | 87,917 | 87,917 | |
| 10 | | | | | |
| 11 | OPUC Docket UM 1971 | | 37,519 | 37,519 | |
| 12 | | | | | |
| 13 | OPUC Docket UM 2009 | | 407,969 | 407,969 | |
| 14 | | | | | |
| 15 | OPUC Docket UM 2032 | | 127,442 | 127,442 | |
| 16 | | | | | |
| 17 | OPUC Docket UM 2051 | | 174,115 | 174,115 | |
| 18 | | | | | |
| 19 | OPUC Docket UM 2057 | | 148,416 | 148,416 | |
| 20 | | | | | |
| 21 | OPUC Docket UM 2074 | | 85,667 | 85,667 | |
| 22 | | | | | |
| 23 | OPUC matters less than $25,000 | | 319,735 | 319,735 | |
| 24 | | | | | |
| 25 | Unassigned Non-Doc Matters | | 378,842 | 378,842 | |
| 26 | | | | | |
| 27 | | | | | |
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| 44 | | | | | |
| 45 | | | | | |
| 46 | TOTAL | | 2,180,003 | 2,180,003 | |

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 | 283,706 | | | | | 1 |
| | | | | | | | 2 |
| | | | | | | | 3 |
| | 928 | 118,110 | | | | | 4 |
| | | | | | | | 5 |
| | | | | | | | 6 |
| | 928 | 10,565 | | | | | 7 |
| | | | | | | | 8 |
| | 928 | 87,917 | | | | | 9 |
| | | | | | | | 10 |
| | 928 | 37,519 | | | | | 11 |
| | | | | | | | 12 |
| | 928 | 407,969 | | | | | 13 |
| | | | | | | | 14 |
| | 928 | 127,442 | | | | | 15 |
| | | | | | | | 16 |
| | 928 | 174,115 | | | | | 17 |
| | | | | | | | 18 |
| | 928 | 148,416 | | | | | 19 |
| | | | | | | | 20 |
| | 928 | 85,667 | | | | | 21 |
| | | | | | | | 22 |
| | 928 | 319,735 | | | | | 23 |
| | | | | | | | 24 |
| | 928 | 378,842 | | | | | 25 |
| | | | | | | | 26 |
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| | | 2,180,003 | | | | | 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<br>(2) [ ] A Resubmission | / / | End of 2020/Q4 |



## RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

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

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

| Line No. | Classification (a) | Description (b) |
|---|---|---|
| 1 | A(1)(c) | Electric R, D & D Performed Internally - Internal combustion or gas turbin |
| 2 | A(6) | Electric R, D & D Performed Internally - Other |
| 3 | B(1) | Electric R, D & D Performed Externally |
| 4 | B(4) | Electric R, D & D Performed Externally |
| 5 | | |
| 6 | | |
| 7 | | |
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| 20 | Totals | |
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| 38 | | |

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



RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

| Costs Incurred Internally Current Year (c) | Costs Incurred Externally Current Year (d) | AMOUNTS CHARGED IN CURRENT YEAR | | Unamortized Accumulation (g) | Line No. |
|---|---|---|---|---|---|
| | | Account (e) | Amount (f) | | |
| 154,700 | | 930.2 | 154,700 | | 1 |
| 136,641 | | 930.2 | 136,641 | | 2 |
| | 1,578,150 | 930.2 | 1,578,150 | | 3 |
| | 531,795 | 930.2 | 531,795 | | 4 |
| | | | | | 5 |
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| | | | | | 18 |
| | | | | | 19 |
| 291,341 | 2,109,945 | | 2,401,286 | | 20 |
| | | | | | 21 |
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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 | 32,842,457 | | |
| 4 | Transmission | 6,888,520 | | |
| 5 | Regional Market | | | |
| 6 | Distribution | 10,342,161 | | |
| 7 | Customer Accounts | 25,168,449 | | |
| 8 | Customer Service and Informational | 6,922,223 | | |
| 9 | Sales | | | |
| 10 | Administrative and General | 37,259,129 | | |
| 11 | TOTAL Operation (Enter Total of lines 3 thru 10) | 119,422,939 | | |
| 12 | Maintenance | | | |
| 13 | Production | 12,540,044 | | |
| 14 | Transmission | 869,120 | | |
| 15 | Regional Market | | | |
| 16 | Distribution | 25,632,916 | | |
| 17 | Administrative and General | 1,300,033 | | |
| 18 | TOTAL Maintenance (Total of lines 13 thru 17) | 40,342,113 | | |
| 19 | Total Operation and Maintenance | | | |
| 20 | Production (Enter Total of lines 3 and 13) | 45,382,501 | | |
| 21 | Transmission (Enter Total of lines 4 and 14) | 7,757,640 | | |
| 22 | Regional Market (Enter Total of Lines 5 and 15) | | | |
| 23 | Distribution (Enter Total of lines 6 and 16) | 35,975,077 | | |
| 24 | Customer Accounts (Transcribe from line 7) | 25,168,449 | | |
| 25 | Customer Service and Informational (Transcribe from line 8) | 6,922,223 | | |
| 26 | Sales (Transcribe from line 9) | | | |
| 27 | Administrative and General (Enter Total of lines 10 and 17) | 38,559,162 | | |
| 28 | TOTAL Oper. and Maint. (Total of lines 20 thru 27) | 159,765,052 | 28,729,458 | 188,494,510 |
| 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) | 159,765,052 | 28,729,458 | 188,494,510 |
| 66 | Utility Plant | | | |
| 67 | Construction (By Utility Departments) | | | |
| 68 | Electric Plant | 121,503,485 | 4,760,690 | 126,264,175 |
| 69 | Gas Plant | | | |
| 70 | Other (provide details in footnote): | | | |
| 71 | TOTAL Construction (Total of lines 68 thru 70) | 121,503,485 | 4,760,690 | 126,264,175 |
| 72 | Plant Removal (By Utility Departments) | | | |
| 73 | Electric Plant | 2,611,505 | 118,918 | 2,730,423 |
| 74 | Gas Plant | | | |
| 75 | Other (provide details in footnote): | | | |
| 76 | TOTAL Plant Removal (Total of lines 73 thru 75) | 2,611,505 | 118,918 | 2,730,423 |
| 77 | Other Accounts (Specify, provide details in footnote): | | | |
| 78 | Other Income and Deductions | 1,360,421 | 308,193 | 1,668,614 |
| 79 | Co-Owner Shares of Generating Facilities | 5,133,579 | 250,015 | 5,383,594 |
| 80 | Other | 8,468,060 | 452,106 | 8,920,166 |
| 81 | Payroll Allocated | 34,619,380 | -34,619,380 | |
| 82 | | | | |
| 83 | | | | |
| 84 | | | | |
| 85 | | | | |
| 86 | | | | |
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| 93 | | | | |
| 94 | | | | |
| 95 | TOTAL Other Accounts | 49,581,440 | -33,609,066 | 15,972,374 |
| 96 | TOTAL SALARIES AND WAGES | 333,461,482 | | 333,461,482 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2020/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<br>(2) [ ] A Resubmission | // | End of 2020/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) | 2,413,966 | 322,215 | 1,366,660 | 6,522,780 |
| 3 | Net Sales (Account 447) | 18,527,663 | 9,017,384 | 10,960,439 | 57,852,640 |
| 4 | Transmission Rights | | | | |
| 5 | Ancillary Services | | | | |
| 6 | Other Items (list separately) | | | | |
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| 41 | | | | | |
| 42 | | | | | |
| 43 | | | | | |
| 44 | | | | | |
| 45 | | | | | |
| 46 | TOTAL | 20,941,629 | 9,339,599 | 12,327,099 | 64,375,420 |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) X An Original<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

***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.

## 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.

| Line No. | Type of Ancillary Service (a) | Amount Purchased for the Year | | | Amount Sold for the Year | | |
|---|---|---|---|---|---|---|---|
| | | Usage - Related Billing Determinant | | | Usage - Related Billing Determinant | | |
| | | 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 | 171,445 | MWH | 15,262,431 | 6,251,208 | MWH | 161,099 |
| 2 | Reactive Supply and Voltage | | | | 4,125,740 | MWH | 135,446 |
| 3 | Regulation and Frequency Response | | | | 4,124,612 | MWH | 302,029 |
| 4 | Energy Imbalance | 130,607 | MWH | 2,408,358 | 952,519 | MWH | 1,459,496 |
| 5 | Operating Reserve - Spinning | | | | 3,417 | MW | 343,152 |
| 6 | Operating Reserve - Supplement | | | | 3,417 | MW | 343,152 |
| 7 | Other | | | | | | |
| 8 | Total (Lines 1 thru 7) | 302,052 | | 17,670,789 | 15,460,913 | | 2,744,374 |

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

***Schedule Page: 398 Line No.: 4 Column: b***

The Energy Imbalance Number of Units is based on difference of each transmission customer's hourly base schedule less their actual hourly energy usage by retail customers. Over scheduled amounts represent actual energy usage less than their scheduled amount. PGE purchases the over scheduled energy quantity from the transmission customers.

***Schedule Page: 398 Line No.: 4 Column: d***

The Amount Purchased for the Energy Imbalance Dollars amount is based on the CAISO OASIS published hourly LMP prices for the PGE ELAP in the Western EIM market multipled by their over scheduled amount.

***Schedule Page: 398 Line No.: 4 Column: e***

The Energy Imbalance Number of Units is based on difference of each transmission customer's hourly base schedule less their actual hourly energy usage by retail customers. Under scheduled amounts represent actual energy usage greater than their scheduled amount. PGE sells the under scheduled energy quanity to the transmission customers.

***Schedule Page: 398 Line No.: 4 Column: g***

The Amount Purchased for the Energy Imbalance Dollars amount is based on the CAISO OASIS published hourly LMP prices for the PGE ELAP in the Western EIM market multipled by their under scheduled amount.

***Schedule Page: 398 Line No.: 5 Column: e***

The Number of Units value represents the hourly peak scheduled value for each transmission customer at the monthly system peak, summed over the 12 months of the year per the OATT schedule formula.

***Schedule Page: 398 Line No.: 6 Column: e***

The Number of Units value represents the hourly peak scheduled value for each transmission customer at the monthly system peak, summed over the 12 months of the year per the OATT schedule formula.

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



## MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: PGE

| Line No. | Month (a) | Monthly Peak MW - Total (b) | Day of Monthly Peak (c) | Hour of Monthly Peak (d) | Firm Network Service for Self (e) | Firm Network Service for Others (f) | Long-Term Firm Point-to-point Reservations (g) | Other Long-Term Firm Service (h) | Short-Term Firm Point-to-point Reservation (i) | Other Service (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | January | 4,948 | 27 | 10 | 2,520 | 280 | 2,661 | 66 | 1,502 | 179 |
| 2 | February | 4,937 | 3 | 19 | 2,888 | 275 | 2,661 | 78 | 1,502 | 132 |
| 3 | March | 4,500 | 2 | 21 | 2,543 | 270 | 2,661 | 66 | 1,708 | |
| 4 | Total for Quarter 1 | | | | 7,951 | 825 | 7,983 | 210 | 4,712 | 311 |
| 5 | April | 4,548 | 3 | 11 | 2,480 | 258 | 2,661 | 61 | 2,058 | 227 |
| 6 | May | 4,637 | 28 | 19 | 2,824 | 298 | 2,661 | 61 | 1,908 | 104 |
| 7 | June | 4,410 | 23 | 22 | 2,767 | 297 | 2,661 | 56 | 1,508 | 54 |
| 8 | Total for Quarter 2 | | | | 8,071 | 853 | 7,983 | 178 | 5,474 | 385 |
| 9 | July | 5,200 | 20 | 20 | 3,264 | 311 | 2,661 | 86 | 1,508 | 106 |
| 10 | August | 4,976 | 17 | 20 | 3,264 | 321 | 2,661 | 77 | 1,508 | 569 |
| 11 | September | 5,013 | 7 | 18 | 2,856 | 287 | 2,661 | 77 | 1,508 | 105 |
| 12 | Total for Quarter 3 | | | | 9,384 | 919 | 7,983 | 240 | 4,524 | 780 |
| 13 | October | 4,032 | 27 | 9 | 2,750 | 288 | 2,661 | 55 | 1,508 | 294 |
| 14 | November | 4,601 | 30 | 20 | 2,733 | 271 | 2,661 | 65 | 1,908 | 4 |
| 15 | December | 4,947 | 21 | 20 | 2,604 | 251 | 2,661 | 64 | 1,808 | 295 |
| 16 | Total for Quarter 4 | | | | 8,087 | 810 | 7,983 | 184 | 5,224 | 593 |
| 17 | Total Year to Date/Year | | | | 33,493 | 3,407 | 31,932 | 812 | 19,934 | 2,069 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2020/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) | 17,423,803 |
| 3 | Steam | 3,232,095 | 23 | Requirements Sales for Resale (See instruction 4, page 311.) | |
| 4 | Nuclear | | 24 | Non-Requirements Sales for Resale (See instruction 4, page 311.) | 6,442,580 |
| 5 | Hydro-Conventional | 1,204,249 | 25 | Energy Furnished Without Charge | |
| 6 | Hydro-Pumped Storage | | 26 | Energy Used by the Company (Electric Dept Only, Excluding Station Use) | 25,725 |
| 7 | Other | 10,140,288 | 27 | Total Energy Losses | 1,045,901 |
| 8 | Less Energy for Pumping | | 28 | TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20) | 24,938,009 |
| 9 | Net Generation (Enter Total of lines 3 through 8) | 14,576,632 | | | |
| 10 | Purchases | 10,358,031 | | | |
| 11 | Power Exchanges: | | | | |
| 12 | Received | | | | |
| 13 | Delivered | | | | |
| 14 | Net Exchanges (Line 12 minus line 13) | | | | |
| 15 | Transmission For Other (Wheeling) | | | | |
| 16 | Received | 6,818,609 | | | |
| 17 | Delivered | 6,815,263 | | | |
| 18 | Net Transmission for Other (Line 16 minus line 17) | 3,346 | | | |
| 19 | Transmission By Others Losses | | | | |
| 20 | TOTAL (Enter Total of lines 9, 10, 14, 18 and 19) | 24,938,009 | | | |

## 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 | 2,400,930 | 700,599 | 3,330 | 14 | 19 |
| 30 | February | 2,167,445 | 595,848 | 3,259 | 4 | 8 |
| 31 | March | 2,230,913 | 643,460 | 3,117 | 9 | 8 |
| 32 | April | 1,870,056 | 518,443 | 2,804 | 1 | 11 |
| 33 | May | 1,825,915 | 472,278 | 3,114 | 28 | 18 |
| 34 | June | 1,721,238 | 372,523 | 3,408 | 23 | 18 |
| 35 | July | 2,174,905 | 617,050 | 3,771 | 27 | 18 |
| 36 | August | 2,222,254 | 624,827 | 3,696 | 17 | 18 |
| 37 | September | 2,112,194 | 659,874 | 3,661 | 3 | 18 |
| 38 | October | 1,983,955 | 503,546 | 3,024 | 27 | 9 |
| 39 | November | 2,053,865 | 430,077 | 3,157 | 9 | 18 |
| 40 | December | 2,170,993 | 414,146 | 3,367 | 29 | 18 |
| 41 | TOTAL | 24,934,663 | 6,552,671 | | | |

***Schedule Page: 401 Line No.: 9 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 2,111,182 megawatt hours of net wind energy from PGE's Biglow Canyon Wind Farm, Tucannon River Wind Farm and Wheatridge Wind Farm.

Actual Gross wind generation from the wind farms was 2,118,799 megawatt hours.

The Biglow 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 12/31/2020: $941,644,956
Total installed capacity: 450 megawatts
Operations and maintenance expense for 2020: $14,894,590

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

In-service production cost at 12/31/2020: $487,294,286
Total installed capacity: 267 megawatts
Operations and maintenance expense for 2020: $8,058,003

The Wheatridge Wind Farm was placed in service in December, 2020. Key statistics include the following:

In-service production cost at 12/31/2020: $151,796,820
Total installed capacity: 100 megawatts
Operations and maintenance expense for 2020: $172,988

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

PGE has ownership in a 5 megawatt storage battery (Salem Smart Power Center) with a FERC 101 Plant-in-service balance of $384,933 as of 12/31/2020, 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 2020 to FERC 592.2 - Maintenance of Energy Storage Equipment $34,703. Line loss includes approximately 0.84 MWh of energy stored in the battery as of 12/31/2020.

## 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) | 575 | | | 0 | | |
| 7 | Plant Hours Connected to Load | 3560 | | | 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 | 62 | | | 0 | | |
| 12 | Net Generation, Exclusive of Plant Use - KWh | 1616407000 | | | 1477803000 | | |
| 13 | Cost of Plant: Land and Land Rights | 0 | | | 0 | | |
| 14 | Structures and Improvements | 0 | | | 0 | | |
| 15 | Equipment Costs | 0 | | | 0 | | |
| 16 | Asset Retirement Costs | 0 | | | 0 | | |
| 17 | Total Cost | 0 | | | 0 | | |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | 0.0000 | | | 0.0000 | | |
| 19 | Production Expenses: Oper, Supv, & Engr | 2676286 | | | 2276048 | | |
| 20 | Fuel | 43129093 | | | 39463121 | | |
| 21 | Coolants and Water (Nuclear Plants Only) | 0 | | | 0 | | |
| 22 | Steam Expenses | 14446373 | | | 13491345 | | |
| 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 | 4342562 | | | 3662198 | | |
| 27 | Rents | 0 | | | 0 | | |
| 28 | Allowances | 0 | | | 0 | | |
| 29 | Maintenance Supervision and Engineering | 184330 | | | 233500 | | |
| 30 | Maintenance of Structures | 178690 | | | 147643 | | |
| 31 | Maintenance of Boiler (or reactor) Plant | 337907 | | | 276981 | | |
| 32 | Maintenance of Electric Plant | 3969200 | | | 3357353 | | |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | 291417 | | | 263323 | | |
| 34 | Total Production Expenses | 69555858 | | | 63171512 | | |
| 35 | Expenses per Net KWh | 0.0430 | | | 0.0427 | | |
| 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 | 983210 | 3927 | 0 | 0 | 0 | 0 |
| 39 | Avg Heat Cont - Fuel Burned (btu/indicate if nuclear) | 8611 | 138800 | 0 | 0 | 0 | 0 |
| 40 | Avg Cost of Fuel/unit, as Delvd f.o.b. during year | 42.216 | 87.606 | 0.000 | 0.000 | 0.000 | 0.000 |
| 41 | Average Cost of Fuel per Unit Burned | 43.516 | 87.606 | 0.000 | 0.000 | 0.000 | 0.000 |
| 42 | Average Cost of Fuel Burned per Million BTU | 2.527 | 15.040 | 0.000 | 0.000 | 0.000 | 0.000 |
| 43 | Average Cost of Fuel Burned per KWh Net Gen | 0.027 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 44 | Average BTU per KWh Net Generation | 10475.600 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original (2) [ ] A Resubmission | / / | End of 2020/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 | | | 1754292000 | | |
| 13 | Cost of Plant: Land and Land Rights | 0 | | | 3328862 | | |
| 14 | Structures and Improvements | 0 | | | 117298194 | | |
| 15 | Equipment Costs | 0 | | | 374230633 | | |
| 16 | Asset Retirement Costs | 0 | | | 34911263 | | |
| 17 | Total Cost | 0 | | | 529768952 | | |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | 0 | | | 1702.3424 | | |
| 19 | Production Expenses: Oper, Supv, & Engr | 0 | | | 74997 | | |
| 20 | Fuel | 0 | | | 31213031 | | |
| 21 | Coolants and Water (Nuclear Plants Only) | 0 | | | 0 | | |
| 22 | Steam Expenses | 0 | | | 2342810 | | |
| 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 | | | 4241461 | | |
| 27 | Rents | 0 | | | 0 | | |
| 28 | Allowances | 0 | | | 0 | | |
| 29 | Maintenance Supervision and Engineering | 0 | | | 731398 | | |
| 30 | Maintenance of Structures | 0 | | | 846009 | | |
| 31 | Maintenance of Boiler (or reactor) Plant | 0 | | | 7904507 | | |
| 32 | Maintenance of Electric Plant | 0 | | | 1739158 | | |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | 0 | | | 573286 | | |
| 34 | Total Production Expenses | 0 | | | 49666657 | | |
| 35 | Expenses per Net KWh | 0.0000 | | | 0.0283 | | |
| 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<br>(2) [ ] A Resubmission | / / | End of 2020/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: (c) | | |
|---|---|---|---|---|---|---|---|
| 1 | Kind of Plant (Internal Comb, Gas Turb, Nuclear | | | | | | |
| 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 | | | 0.00 | | |
| 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 | | | 0 | | |
| 13 | Cost of Plant: Land and Land Rights | 0 | | | 0 | | |
| 14 | Structures and Improvements | 0 | | | 0 | | |
| 15 | Equipment Costs | 0 | | | 0 | | |
| 16 | Asset Retirement Costs | 0 | | | 0 | | |
| 17 | Total Cost | 0 | | | 0 | | |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | 0 | | | 0 | | |
| 19 | Production Expenses: Oper, Supv, & Engr | 0 | | | 0 | | |
| 20 | Fuel | 0 | | | 0 | | |
| 21 | Coolants and Water (Nuclear Plants Only) | 0 | | | 0 | | |
| 22 | Steam Expenses | 0 | | | 0 | | |
| 23 | Steam From Other Sources | 0 | | | 0 | | |
| 24 | Steam Transferred (Cr) | 0 | | | 0 | | |
| 25 | Electric Expenses | 0 | | | 0 | | |
| 26 | Misc Steam (or Nuclear) Power Expenses | 0 | | | 0 | | |
| 27 | Rents | 0 | | | 0 | | |
| 28 | Allowances | 0 | | | 0 | | |
| 29 | Maintenance Supervision and Engineering | 0 | | | 0 | | |
| 30 | Maintenance of Structures | 0 | | | 0 | | |
| 31 | Maintenance of Boiler (or reactor) Plant | 0 | | | 0 | | |
| 32 | Maintenance of Electric Plant | 0 | | | 0 | | |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | 0 | | | 0 | | |
| 34 | Total Production Expenses | 0 | | | 0 | | |
| 35 | Expenses per Net KWh | 0.0000 | | | 0.0000 | | |
| 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<br>(2) [ ] A Resubmission | // | End of 2020/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: (c) | | |
|---|---|---|---|---|---|---|---|
| 1 | Kind of Plant (Internal Comb, Gas Turb, Nuclear | | | | | | |
| 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 | | | 0.00 | | |
| 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 | | | 0 | | |
| 13 | Cost of Plant: Land and Land Rights | 0 | | | 0 | | |
| 14 | Structures and Improvements | 0 | | | 0 | | |
| 15 | Equipment Costs | 0 | | | 0 | | |
| 16 | Asset Retirement Costs | 0 | | | 0 | | |
| 17 | Total Cost | 0 | | | 0 | | |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | 0 | | | 0 | | |
| 19 | Production Expenses: Oper, Supv, & Engr | 0 | | | 0 | | |
| 20 | Fuel | 0 | | | 0 | | |
| 21 | Coolants and Water (Nuclear Plants Only) | 0 | | | 0 | | |
| 22 | Steam Expenses | 0 | | | 0 | | |
| 23 | Steam From Other Sources | 0 | | | 0 | | |
| 24 | Steam Transferred (Cr) | 0 | | | 0 | | |
| 25 | Electric Expenses | 0 | | | 0 | | |
| 26 | Misc Steam (or Nuclear) Power Expenses | 0 | | | 0 | | |
| 27 | Rents | 0 | | | 0 | | |
| 28 | Allowances | 0 | | | 0 | | |
| 29 | Maintenance Supervision and Engineering | 0 | | | 0 | | |
| 30 | Maintenance of Structures | 0 | | | 0 | | |
| 31 | Maintenance of Boiler (or reactor) Plant | 0 | | | 0 | | |
| 32 | Maintenance of Electric Plant | 0 | | | 0 | | |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | 0 | | | 0 | | |
| 34 | Total Production Expenses | 0 | | | 0 | | |
| 35 | Expenses per Net KWh | 0.0000 | | | 0.0000 | | |
| 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<br>(2) [ ] A Resubmission | / / | End of 2020/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 | | | 296.00 | | | 5 |
| 398 | | | 426 | | | 276 | | | 6 |
| 2111 | | | 6979 | | | 6656 | | | 7 |
| 0 | | | 0 | | | 0 | | | 8 |
| 533 | | | 421 | | | 270 | | | 9 |
| 0 | | | 0 | | | 0 | | | 10 |
| 45 | | | 27 | | | 32 | | | 11 |
| 371881000 | | | 2640315000 | | | 1596387000 | | | 12 |
| 24473 | | | 24473 | | | 0 | | | 13 |
| 38076651 | | | 42833536 | | | 11634202 | | | 14 |
| 222580002 | | | 243525017 | | | 190146850 | | | 15 |
| 2941318 | | | 231072 | | | 113193 | | | 16 |
| 263622444 | | | 286614098 | | | 201894245 | | | 17 |
| 459.9135 | | | 593.0356 | | | 682.0752 | | | 18 |
| 512145 | | | 845764 | | | 126386 | | | 19 |
| 9500116 | | | 53506856 | | | 26598222 | | | 20 |
| 0 | | | 0 | | | 0 | | | 21 |
| 0 | | | 0 | | | 0 | | | 22 |
| 0 | | | 0 | | | 0 | | | 23 |
| 0 | | | 0 | | | 0 | | | 24 |
| 1716231 | | | 2619308 | | | 1201579 | | | 25 |
| 2385403 | | | 1577882 | | | 751021 | | | 26 |
| 217035 | | | 28586 | | | 0 | | | 27 |
| 0 | | | 0 | | | 0 | | | 28 |
| 1358329 | | | 248644 | | | -27773 | | | 29 |
| 127897 | | | 35740 | | | 53307 | | | 30 |
| 0 | | | 0 | | | 0 | | | 31 |
| 2732268 | | | 5165519 | | | 5155522 | | | 32 |
| 349261 | | | 71785 | | | 37169 | | | 33 |
| 18898685 | | | 64100084 | | | 33895433 | | | 34 |
| 0.0508 | | | 0.0243 | | | 0.0212 | | | 35 |
| Gas | Oil | | Gas | Oil | | Gas | Oil | | 36 |
| Mcf's | Barrels | | Mcf's | Barrels | | Mcf's | Barrels | | 37 |
| 3807558 | 353 | 0 | 18135983 | 0 | 0 | 11347215 | 0 | 0 | 38 |
| 1019000 | 138690 | 0 | 1019000 | 138690 | 0 | 1019000 | 138690 | 0 | 39 |
| 2.480 | 0.000 | 0.000 | 2.537 | 0.000 | 0.000 | 1.831 | 0.000 | 0.000 | 40 |
| 2.486 | 97.371 | 0.000 | 2.950 | 0.000 | 0.000 | 2.344 | 0.000 | 0.000 | 41 |
| 2.439 | 16.748 | 0.000 | 2.894 | 0.000 | 0.000 | 2.299 | 0.000 | 0.000 | 42 |
| 0.026 | 0.000 | 0.000 | 0.020 | 0.000 | 0.000 | 0.017 | 0.000 | 0.000 | 43 |
| 10442.476 | 0.000 | 0.000 | 7001.900 | 0.000 | 0.000 | 7245.700 | 0.000 | 0.000 | 44 |

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

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

| Plant Name: *Port Westward 2* (d) | Plant Name: *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 | 466 | 0 | 6 |
| 3999 | 7208 | 0 | 7 |
| 0 | 0 | 0 | 8 |
| 225 | 0 | 0 | 9 |
| 0 | 0 | 0 | 10 |
| 0 | 27 | 0 | 11 |
| 448545000 | 2967457000 | 0 | 12 |
| 0 | 0 | 0 | 13 |
| 42352598 | 86306276 | 0 | 14 |
| 248382121 | 429265205 | 0 | 15 |
| 647461 | 10434861 | 0 | 16 |
| 291382180 | 526006342 | 0 | 17 |
| 1294.4566 | 1045.5304 | 0 | 18 |
| 18168 | 296973 | 0 | 19 |
| 10698762 | 55585824 | 0 | 20 |
| 0 | 0 | 0 | 21 |
| 0 | 0 | 0 | 22 |
| 0 | 0 | 0 | 23 |
| 0 | 0 | 0 | 24 |
| 343287 | 2620924 | 0 | 25 |
| 964531 | 2353703 | 0 | 26 |
| 33347 | 0 | 0 | 27 |
| 0 | 0 | 0 | 28 |
| 9714 | 93877 | 0 | 29 |
| 6403 | -97 | 0 | 30 |
| 0 | 0 | 0 | 31 |
| 1508768 | 6119026 | 0 | 32 |
| 104849 | 271057 | 0 | 33 |
| 13687829 | 67341287 | 0 | 34 |
| 0.0305 | 0.0227 | 0.0000 | 35 |

| (d) | | | (e) | | | (f) | | | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| Gas | Oil | | Gas | Oil | | | | | 36 |
| Mcf's | Barrels | | Mcf's | Barrels | | | | | 37 |
| 3792133 | 0 | 0 | 20011045 | 0 | 0 | 0 | 0 | 0 | 38 |
| 1019000 | 138690 | 0 | 1019000 | 138690 | 0 | 0 | 0 | 0 | 39 |
| 2.976 | 0.000 | 0.000 | 1.836 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 40 |
| 2.821 | 0.000 | 0.000 | 2.778 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 41 |
| 2.767 | 0.000 | 0.000 | 2.725 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 42 |
| 0.024 | 0.000 | 0.000 | 0.019 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 43 |
| 8618.000 | 0.000 | 0.000 | 6874.100 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 44 |

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

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

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

| Plant Name: (d) | | | Plant Name: (e) | | | Plant Name: (f) | | | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |
| | | | | | | | | | 1 |
| | | | | | | | | | 2 |
| | | | | | | | | | 3 |
| | | | | | | | | | 4 |
| 0.00 | | | 0.00 | | | 0.00 | | | 5 |
| 0 | | | 0 | | | 0 | | | 6 |
| 0 | | | 0 | | | 0 | | | 7 |
| 0 | | | 0 | | | 0 | | | 8 |
| 0 | | | 0 | | | 0 | | | 9 |
| 0 | | | 0 | | | 0 | | | 10 |
| 0 | | | 0 | | | 0 | | | 11 |
| 0 | | | 0 | | | 0 | | | 12 |
| 0 | | | 0 | | | 0 | | | 13 |
| 0 | | | 0 | | | 0 | | | 14 |
| 0 | | | 0 | | | 0 | | | 15 |
| 0 | | | 0 | | | 0 | | | 16 |
| 0 | | | 0 | | | 0 | | | 17 |
| 0 | | | 0 | | | 0 | | | 18 |
| 0 | | | 0 | | | 0 | | | 19 |
| 0 | | | 0 | | | 0 | | | 20 |
| 0 | | | 0 | | | 0 | | | 21 |
| 0 | | | 0 | | | 0 | | | 22 |
| 0 | | | 0 | | | 0 | | | 23 |
| 0 | | | 0 | | | 0 | | | 24 |
| 0 | | | 0 | | | 0 | | | 25 |
| 0 | | | 0 | | | 0 | | | 26 |
| 0 | | | 0 | | | 0 | | | 27 |
| 0 | | | 0 | | | 0 | | | 28 |
| 0 | | | 0 | | | 0 | | | 29 |
| 0 | | | 0 | | | 0 | | | 30 |
| 0 | | | 0 | | | 0 | | | 31 |
| 0 | | | 0 | | | 0 | | | 32 |
| 0 | | | 0 | | | 0 | | | 33 |
| 0 | | | 0 | | | 0 | | | 34 |
| 0.0000 | | | 0.0000 | | | 0.0000 | | | 35 |
| | | | | | | | | | 36 |
| | | | | | | | | | 37 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 38 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 39 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 40 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 41 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 42 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 43 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 44 |

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

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

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

| Plant Name: (d) | Plant Name: (e) | Plant Name: (f) | Line No. |
|---|---|---|---|
| | | | |
| | | | 1 |
| | | | 2 |
| | | | 3 |
| | | | 4 |
| 0.00 | 0.00 | 0.00 | 5 |
| 0 | 0 | 0 | 6 |
| 0 | 0 | 0 | 7 |
| 0 | 0 | 0 | 8 |
| 0 | 0 | 0 | 9 |
| 0 | 0 | 0 | 10 |
| 0 | 0 | 0 | 11 |
| 0 | 0 | 0 | 12 |
| 0 | 0 | 0 | 13 |
| 0 | 0 | 0 | 14 |
| 0 | 0 | 0 | 15 |
| 0 | 0 | 0 | 16 |
| 0 | 0 | 0 | 17 |
| 0 | 0 | 0 | 18 |
| 0 | 0 | 0 | 19 |
| 0 | 0 | 0 | 20 |
| 0 | 0 | 0 | 21 |
| 0 | 0 | 0 | 22 |
| 0 | 0 | 0 | 23 |
| 0 | 0 | 0 | 24 |
| 0 | 0 | 0 | 25 |
| 0 | 0 | 0 | 26 |
| 0 | 0 | 0 | 27 |
| 0 | 0 | 0 | 28 |
| 0 | 0 | 0 | 29 |
| 0 | 0 | 0 | 30 |
| 0 | 0 | 0 | 31 |
| 0 | 0 | 0 | 32 |
| 0 | 0 | 0 | 33 |
| 0 | 0 | 0 | 34 |
| 0.0000 | 0.0000 | 0.0000 | 35 |

| | | | | | | | | | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | 36 |
| | | | | | | | | | 37 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 38 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 39 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 40 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 41 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 42 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 43 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 44 |

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

***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. The Boardman plant was retired in 4Q 2020.

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

Respondent is the principal owner and operator of the Boardman Plant. Installed capacity in line 5c represents 90% share. Reported here are the respondent's share of expenses incurred during the year and investment as of December 31, 2020, as appropriate. Details are reported in Page 402 col (b). The Boardman plant was retired in 4Q 2020.

***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 uses gas extensively for generation with minimal oil usage. The Average BTU per KWH net generation reported is a composite heat rate for both fuels.

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

The Port Westward 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<br>(2) [ ] A Resubmission | / / | End of 2020/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<br>(a) | FERC Licensed Project No. 2195<br>Plant Name: Faraday<br>(b) | FERC Licensed Project No. 2195<br>Plant Name: North Fork<br>(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) | 0 | 57 |
| 7 | Plant Hours Connect to Load | 0 | 8,433 |
| 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 | 53 | 0 |
| 12 | Net Generation, Exclusive of Plant Use - Kwh | -7,000 | 163,729,000 |
| 13 | Cost of Plant | | |
| 14 | Land and Land Rights | 33,434 | 377,100 |
| 15 | Structures and Improvements | 19,021,225 | 9,196,031 |
| 16 | Reservoirs, Dams, and Waterways | 33,030,468 | 85,742,690 |
| 17 | Equipment Costs | 11,734,275 | 13,280,242 |
| 18 | Roads, Railroads, and Bridges | 2,441,325 | 2,767,794 |
| 19 | Asset Retirement Costs | 90 | 6 |
| 20 | TOTAL cost (Total of 14 thru 19) | 66,260,817 | 111,363,863 |
| 21 | Cost per KW of Installed Capacity (line 20 / 5) | 1,800.0765 | 2,216.1963 |
| 22 | Production Expenses | | |
| 23 | Operation Supervision and Engineering | 296,185 | 19,912 |
| 24 | Water for Power | 68,848 | 54,108 |
| 25 | Hydraulic Expenses | 1,353,489 | 660,316 |
| 26 | Electric Expenses | 649,072 | 245,573 |
| 27 | Misc Hydraulic Power Generation Expenses | 777,849 | 490,526 |
| 28 | Rents | 130,044 | 90,043 |
| 29 | Maintenance Supervision and Engineering | 516,954 | 1,072 |
| 30 | Maintenance of Structures | 4,894 | 0 |
| 31 | Maintenance of Reservoirs, Dams, and Waterways | 7,030 | 55,299 |
| 32 | Maintenance of Electric Plant | 108,127 | 17,103 |
| 33 | Maintenance of Misc Hydraulic Plant | 726,817 | 222,363 |
| 34 | Total Production Expenses (total 23 thru 33) | 4,639,309 | 1,856,315 |
| 35 | Expenses per net KWh | 0.0000 | 0.0113 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2020/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<br>(a) | FERC Licensed Project No. 2030<br>Plant Name: Pelton<br>(b) | FERC Licensed Project No. 2030<br>Plant Name: Pelton (PGE%)<br>(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) | 97 | 0 |
| 7 | Plant Hours Connect to Load | 8,765 | 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 | 343,185,000 | 228,790,000 |
| 13 | Cost of Plant | | |
| 14 | Land and Land Rights | 3,681,439 | 2,454,415 |
| 15 | Structures and Improvements | 9,522,633 | 6,359,006 |
| 16 | Reservoirs, Dams, and Waterways | 15,710,616 | 10,705,389 |
| 17 | Equipment Costs | 23,497,467 | 15,917,265 |
| 18 | Roads, Railroads, and Bridges | 6,076,338 | 4,310,174 |
| 19 | Asset Retirement Costs | 52 | 52 |
| 20 | TOTAL cost (Total of 14 thru 19) | 58,488,545 | 39,746,301 |
| 21 | Cost per KW of Installed Capacity (line 20 / 5) | 530.7490 | 540.9868 |
| 22 | Production Expenses | | |
| 23 | Operation Supervision and Engineering | 305,245 | 188,911 |
| 24 | Water for Power | 173,182 | 97,537 |
| 25 | Hydraulic Expenses | 2,479,213 | 1,711,672 |
| 26 | Electric Expenses | 286,068 | 187,021 |
| 27 | Misc Hydraulic Power Generation Expenses | 803,937 | 535,346 |
| 28 | Rents | 10,679 | 4,626 |
| 29 | Maintenance Supervision and Engineering | 368,568 | 245,715 |
| 30 | Maintenance of Structures | 0 | 0 |
| 31 | Maintenance of Reservoirs, Dams, and Waterways | 51,446 | 51,446 |
| 32 | Maintenance of Electric Plant | 249,728 | 120,052 |
| 33 | Maintenance of Misc Hydraulic Plant | 229,446 | 140,132 |
| 34 | Total Production Expenses (total 23 thru 33) | 4,957,512 | 3,282,458 |
| 35 | Expenses per net KWh | 0.0144 | 0.0143 |

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<br>Plant Name: River Mill<br>(d) | FERC Licensed Project No. 2195<br>Plant Name: Oak Grove<br>(e) | FERC Licensed Project No. 2233<br>Plant Name: Sullivan<br>(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 |
| 8,236 | 6,026 | 8,234 | 7 |
| | | | 8 |
| 25 | 44 | 18 | 9 |
| 4 | 19 | 7 | 10 |
| 0 | 4 | 1 | 11 |
| 84,451,000 | 105,388,000 | 106,730,000 | 12 |
| | | | 13 |
| 86,408 | 9,457 | 572,077 | 14 |
| 7,518,906 | 16,202,242 | 19,611,993 | 15 |
| 58,745,880 | 27,259,810 | 31,499,172 | 16 |
| 11,739,936 | 23,960,463 | 14,507,819 | 17 |
| 421,796 | 3,961,942 | 0 | 18 |
| 64 | 2,122 | 2,630 | 19 |
| 78,512,990 | 71,396,036 | 66,193,691 | 20 |
| 3,811.3102 | 1,399.9223 | 4,298.2916 | 21 |
| | | | 22 |
| 14,256 | 21,394 | 2,347 | 23 |
| 44,773 | 67,806 | 37,074 | 24 |
| 313,233 | 1,202,553 | 205,588 | 25 |
| 32,375 | 100,045 | 234,482 | 26 |
| 293,013 | 401,411 | 221,475 | 27 |
| 0 | 562,343 | 0 | 28 |
| 1,098 | 167,431 | 298 | 29 |
| 0 | 0 | 0 | 30 |
| 1,989 | 4,656 | 74,206 | 31 |
| 310,619 | 222,331 | 205,836 | 32 |
| 65,840 | 126,378 | 41,629 | 33 |
| 1,077,196 | 2,876,348 | 1,022,935 | 34 |
| 0.0128 | 0.0273 | 0.0096 | 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<br>(2) [ ] A Resubmission | // | End of 2020/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<br>Plant Name: Round Butte<br>(d) | FERC Licensed Project No. 2030<br>Plant Name: Round Butte (PGE%)<br>(e) | FERC Licensed Project No. 0<br>Plant Name:<br>(f) | Line No. |
|---|---|---|---|
| | | | |
| | | | |
| Storage | Storage | | 1 |
| Conventional | Conventional | | 2 |
| 1964 | 1964 | | 3 |
| 1964 | 1964 | | 4 |
| 372.50 | 248.33 | 0.00 | 5 |
| 232 | 0 | 0 | 6 |
| 8,768 | 0 | 0 | 7 |
| | | | 8 |
| 345 | 0 | 0 | 9 |
| 192 | 0 | 0 | 10 |
| 43 | 0 | 0 | 11 |
| 772,752,000 | 515,168,000 | 0 | 12 |
| | | | 13 |
| 3,726,481 | 2,521,012 | 0 | 14 |
| 18,803,549 | 12,575,060 | 0 | 15 |
| 170,622,348 | 111,482,004 | 0 | 16 |
| 52,832,304 | 40,364,041 | 0 | 17 |
| 2,564,265 | 1,794,840 | 0 | 18 |
| 165 | 165 | 0 | 19 |
| 248,549,112 | 168,737,122 | 0 | 20 |
| 667.2459 | 679.4875 | 0.0000 | 21 |
| | | | 22 |
| 386,191 | 244,005 | 0 | 23 |
| 331,167 | 238,712 | 0 | 24 |
| 2,640,385 | 1,702,280 | 0 | 25 |
| 374,308 | 253,251 | 0 | 26 |
| 983,796 | 655,518 | 0 | 27 |
| 29,676 | 22,278 | 0 | 28 |
| 212,050 | 61,896 | 0 | 29 |
| 0 | 0 | 0 | 30 |
| 167,460 | 167,460 | 0 | 31 |
| 530,310 | 371,817 | 0 | 32 |
| 366,037 | 256,876 | 0 | 33 |
| 6,021,380 | 3,974,093 | 0 | 34 |
| 0.0078 | 0.0077 | 0.0000 | 35 |

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

***Schedule Page: 406 Line No.: 6 Column: b***

Repowering project has been undertaken at the Faraday Powerhouse throughout the current fiscal year. The project includes removing Unit 1-5 and replacing with three new units.

***Schedule Page: 406 Line No.: 7 Column: b***

Repowering project has been undertaken at the Faraday Powerhouse throughout the current fiscal year. The project includes removing Unit 1-5 and replacing with three new units.

***Schedule Page: 406 Line No.: 12 Column: b***

Repowering project has been undertaken at the Faraday Powerhouse throughout the current fiscal year. The project includes removing Unit 1-5 and replacing with three new units.

***Schedule Page: 406.1 Line No.: -1 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.: -1 Column: c***

Jointly owned. Installed capacity on line 5 represents 66.67% share. Details reported on 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.: -1 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.: -1 Column: e***

Jointly owned. Installed capacity on line 5 represents 66.67% share. Details reported on 406.1, 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***

This number 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 2020/Q4 |

## PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

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

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

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.<br>Plant Name:<br>(c) | FERC Licensed Project No.<br>Plant Name:<br>(d) | FERC Licensed Project No.<br>Plant Name:<br>(e) | Line No. |
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| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2020/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 | 9 | 133,799 |
| 2 | Oregon Military Dept/A.F.R.C | 2001 | 1.60 | 1.6 | 54 | 186,058 |
| 3 | US Bank Corp Columbia Center | 2001 | 6.89 | 6.2 | 1,018 | 488,057 |
| 4 | Portland State University | 2004 | 2.80 | 2.8 | 32 | 261,732 |
| 5 | Oregon Military Joint Forces HQ | 2005 | 1.60 | 1.6 | 58 | 191,439 |
| 6 | Stimson Lumber | 2005 | 0.57 | 0.5 | 13 | 159,546 |
| 7 | Flexential (Formerly ViaWest) | 2005 | 9.00 | 8.0 | 1,127 | 629,125 |
| 8 | Skyline | 2005 | 2.00 | 1.8 | 44 | 201,526 |
| 9 | Tri-Quint | 2005 | 0.60 | 0.5 | 2 | 109,968 |
| 10 | NCCWC- Filter Plant | 2005 | 2.00 | 1.8 | 31 | 122,958 |
| 11 | PCC Structurals | 2005 | 1.00 | 0.9 | 9 | 113,874 |
| 12 | Providence Portland Medical Center | 2005 | 6.00 | 5.4 | 487 | 265,383 |
| 13 | Salem Hospital | 2006 | 8.00 | 7.2 | 498 | 269,108 |
| 14 | Sunrise Water Authority Pump Station | 2006 | 1.25 | 1.1 | 11 | 88,272 |
| 15 | Providence Newberg Hospital | 2006 | 1.50 | 1.4 | 108 | 156,833 |
| 16 | vXchnge (Formerly Sungard DSG) | 2006 | 2.00 | 1.8 | 26 | 331,845 |
| 17 | Kaiser Sunnyside Hospital | 2007 | 4.50 | 4.1 | 551 | 352,752 |
| 18 | Newberg Waste Water Treatment Plant | 2008 | 2.00 | 1.8 | 32 | 154,458 |
| 19 | Xerox Corp | 2007 | 4.00 | 3.6 | 108 | 380,259 |
| 20 | Newberg Water Treatment Plant | 2007 | 1.00 | 0.9 | 19 | 78,159 |
| 21 | Oregon Dept of Admin Serv - Data Center | 2010 | 2.60 | 2.3 | 240 | 277,254 |
| 22 | Panasonic (Formerly Sanyo) | 2010 | 1.00 | 0.9 | 13 | 43,144 |
| 23 | Sysco Foods | 2010 | 2.00 | 1.8 | 27 | 184,779 |
| 24 | Clackamas Intertie 2 | 2012 | 0.60 | 0.5 | 8 | 155,832 |
| 25 | Dawson Creek | 2012 | 0.80 | 0.7 | 12 | 95,706 |
| 26 | Kaiser Westside Hospital | 2012 | 4.00 | 3.6 | 210 | 408,830 |
| 27 | North Plains Pump Station | 2012 | 0.80 | 0.7 | 12 | 53,132 |
| 28 | Oak Lodge Sanitary District | 2012 | 2.00 | 1.8 | 29 | 229,144 |
| 29 | Oregon Dept of Admin Serv - Revenue Bldg | 2012 | 1.50 | 1.4 | 21 | 284,255 |
| 30 | Oregon State Hospital | 2012 | 4.00 | 3.6 | 189 | 172,879 |
| 31 | Portland Service Center | 2012 | 0.50 | 0.5 | 10 | 322,856 |
| 32 | Sandy High School | 2012 | 1.25 | 1.1 | 23 | 179,894 |
| 33 | TATA Communications - Hillsboro | 2012 | 3.56 | 3.2 | 157 | 328,979 |
| 34 | Tri-City Wastewater Treatment Plant | 2012 | 2.50 | 2.3 | 36 | 161,695 |
| 35 | TATA Communications - Portland | 2013 | 6.60 | 5.4 | 225 | 612,983 |
| 36 | City of Hillsboro Crandall Reservoir | 2013 | 0.80 | 0.7 | 13 | 105,854 |
| 37 | East County Courts | 2013 | 1.50 | 1.4 | 163 | 316,848 |
| 38 | City of Portland-Columbia Blvd WWTP | 2013 | 1.00 | 0.9 | 13 | 162,234 |
| 39 | Food Services of America | 2013 | 2.00 | 1.8 | 26 | 229,875 |
| 40 | Avery DSG | 2014 | 0.80 | 0.7 | 13 | 263,782 |
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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 | Carver (Readiness Center) DSG | 2014 | 2.00 | 1.8 | 74 | 818,635 |
| 2 | Juvenile Justice Center | 2014 | 0.75 | 0.7 | 20 | 171,380 |
| 3 | Clackamas River Water DSG | 2014 | 2.00 | 1.8 | 31 | 383,436 |
| 4 | Joint Water Commission | 2015 | 5.00 | 4.5 | 146 | 190,302 |
| 5 | McLane Foodservice | 2016 | 1.50 | 1.4 | 23 | 181,242 |
| 6 | Flexential Brookwood (Formerly ViaWest Brookwoo) | 2016 | 16.25 | 11.4 | 3,722 | 278,175 |
| 7 | World Trade Center | 2017 | 3.20 | 2.9 | 256 | 1,021,168 |
| 8 | Washington County Jail | 2017 | 1.50 | 1.4 | 22 | 325,428 |
| 9 | OHSU - Vaccine Gene Therapy Institute | 2017 | 1.50 | 1.4 | 19 | 364,108 |
| 10 | OHSU - Center for Health & Healing | 2018 | 3.00 | 2.7 | 155 | 347,135 |
| 11 | OHSU - Knight Cancer Research Building | 2018 | 2.00 | 1.8 | 13 | 234,533 |
| 12 | Solar | 2014 | 6.00 | 6.0 | 4,524 | 725,400 |
| 13 | Total | | | | | 14,306,048 |
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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 | | 3,253 | 7,609 | diesel-low s | 1,687 | 1 |
| 116,286 | | | 60,885 | diesel-low s | 1,127 | 2 |
| 70,856 | | | 107,245 | diesel-low s | 1,127 | 3 |
| 93,476 | | | 58,183 | diesel-low s | 1,127 | 4 |
| 119,649 | | 8,068 | 38,648 | diesel-low s | 1,478 | 5 |
| 282,382 | | 955 | 16,493 | diesel-low s | 1,037 | 6 |
| 69,903 | | 33,173 | 85,592 | diesel-low s | 1,245 | 7 |
| 100,763 | | 5,013 | 18,257 | diesel-low s | 1,120 | 8 |
| 183,280 | | | 12,824 | diesel-low s | 1,127 | 9 |
| 61,479 | | 3,566 | 41,595 | diesel-low s | 1,191 | 10 |
| 113,874 | | 735 | 13,361 | diesel-low s | 1,026 | 11 |
| 44,231 | | 15,217 | 29,356 | diesel-low s | 935 | 12 |
| 33,639 | | | 46,769 | diesel-low s | 1,127 | 13 |
| 70,618 | | 2,584 | 10,685 | diesel-low s | 1,468 | 14 |
| 104,555 | | 3,021 | 26,502 | diesel-low s | 978 | 15 |
| 165,923 | | 4,539 | 12,789 | diesel-low s | 1,193 | 16 |
| 78,389 | | 35,878 | 36,873 | diesel-low s | 1,656 | 17 |
| 77,229 | | 4,237 | 24,799 | diesel-low s | 898 | 18 |
| 95,065 | | 9,675 | 18,481 | diesel-low s | 1,240 | 19 |
| 78,159 | | 1,627 | 20,357 | diesel-low s | 993 | 20 |
| 106,636 | | 2,240 | 61,697 | diesel-low s | 687 | 21 |
| 43,144 | | 1,037 | 10,664 | diesel-low s | 1,040 | 22 |
| 92,390 | | 2,287 | 18,956 | diesel-low s | 1,079 | 23 |
| 259,720 | | 1,138 | 19,916 | diesel-low s | 1,173 | 24 |
| 119,633 | | | 19,419 | diesel-low s | 1,127 | 25 |
| 102,208 | | 10,841 | 33,041 | diesel-low s | 860 | 26 |
| 66,415 | | | 10,511 | diesel-low s | 1,127 | 27 |
| 114,572 | | 2,261 | 14,179 | diesel-low s | 910 | 28 |
| 189,503 | | 2,099 | 26,432 | diesel-low s | 1,071 | 29 |
| 43,220 | | | 31,164 | diesel-low s | 1,127 | 30 |
| 645,712 | | | 28,594 | diesel-low s | 1,127 | 31 |
| 143,915 | | 2,409 | 13,907 | diesel-low s | 1,117 | 32 |
| 92,540 | | 13,619 | 44,288 | diesel-low s | 1,214 | 33 |
| 64,678 | | 7,843 | 51,448 | diesel-low s | 1,013 | 34 |
| 92,876 | | 10,431 | 80,908 | diesel-low s | 927 | 35 |
| 132,318 | | 2,064 | 23,547 | diesel-low s | 1,550 | 36 |
| 211,232 | | | 72,754 | diesel-low s | 1,127 | 37 |
| 162,234 | | 1,052 | 12,389 | diesel-low s | 979 | 38 |
| 114,938 | | 3,577 | 8,142 | diesel-low s | 937 | 39 |
| 329,728 | | | 6,166 | diesel-low s | 1,127 | 40 |
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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. |
|---|---|---|---|---|---|---|
| 409,318 | | 3,495 | 17,160 | diesel-low s | 1,364 | 1 |
| 228,507 | | | 6,339 | diesel-low s | 1,127 | 2 |
| 191,718 | | 4,205 | 16,015 | diesel-low s | 1,035 | 3 |
| 38,060 | | 15,200 | 18,304 | diesel-low s | 853 | 4 |
| 120,828 | | 2,455 | 12,237 | diesel-low s | 1,048 | 5 |
| 17,118 | | 62,843 | 137,386 | diesel-low s | 1,082 | 6 |
| 319,115 | | 5,817 | 29,987 | diesel-low s | 1,149 | 7 |
| 216,952 | | | 8,017 | diesel-low s | 1,127 | 8 |
| 242,739 | | 1,670 | 11,590 | diesel-low s | 1,222 | 9 |
| 115,712 | | 4,761 | 20,556 | diesel-low s | 1,072 | 10 |
| 117,267 | | 1,552 | 12,707 | diesel-low s | 1,003 | 11 |
| 120,900 | 542,031 | | 104,742 | solar | | 12 |
| | 542,031 | 296,437 | 1,670,465 | | | 13 |
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TRANSMISSION LINE STATISTICS

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

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH (Pole miles) On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 500KV LINES | | | | | | | |
| 2 | BOARDMAN | GRASSLAND | 500.00 | 500.00 | ST. TOWER | 0.94 | | 1 |
| 3 | CARTY | GRASSLAND | 500.00 | 500.00 | ST. TOWER | 0.75 | | |
| 4 | GRASSLAND | BPA SLATT | 500.00 | 500.00 | ST. TOWER | 16.82 | | |
| 5 | COLSTRIP PROJECT: | | | | | | | |
| 6 | COLSTRIP SWITCHYARD | BROADVIEW 'A' | 500.00 | 500.00 | ST. TOWER | | 112.30 | 1 |
| 7 | COLSTRIP SWITCHYARD | BROADVIEW 'B' | 500.00 | 500.00 | ST. TOWER | | 115.80 | 1 |
| 8 | BROADVIEW SWITCHYARD | TOWNSEND 'A' | 500.00 | 500.00 | ST. TOWER | | 133.40 | 1 |
| 9 | BROADVIEW SWITCHYARD | TOWNSEND 'B' | 500.00 | 500.00 | ST. TOWER | | 133.40 | |
| 10 | COLSTRIP PROJECT | PROJECT LINES | | | | | | |
| 11 | GRIZZLY | ROUND BUTTE | 500.00 | 500.00 | ST. TOWER | 15.60 | | 1 |
| 12 | GRIZZLY | MALIN BPA #2 | 500.00 | 500.00 | ST. TOWER | 178.50 | | 1 |
| 13 | MISCELLANEOUS | MISCELLANEOUS | 500.00 | | | | | |
| 14 | JOHN DAY | GRIZZLY '1' | 500.00 | 500.00 | | | | 1 |
| 15 | JOHN DAY | GRIZZLY '2' | 500.00 | 500.00 | | | | 1 |
| 16 | COYOTE SPRINGS | BPA SLATT | 500.00 | 500.00 | | | | 2 |
| 17 | 500 KV LINES TOT | | | | | | | |
| 18 | TOTAL 500KV LINES | | | | | 212.61 | 494.90 | 10 |
| 19 | | | | | | | | |
| 20 | 230 KV LINES | | | | | | | |
| 21 | BEAVER | PORT WESTWARD | 230.00 | 230.00 | H-WOOD | 0.41 | | 1 |
| 22 | BIGLOW CANYON WF | JOHN DAY #1 BPA | 230.00 | 230.00 | | | | 1 |
| 23 | CENTRAL FERRY BPA | MULLAN (TUCANNON WF) | 230.00 | 230.00 | H-WOOD | 20.70 | | 1 |
| 24 | DALREED PACW | BOARDMAN | 230.00 | 230.00 | H-WOOD | 16.76 | | 1 |
| 25 | PELTON | ROUND BUTTE | 230.00 | 230.00 | H-WOOD | 7.87 | | 1 |
| 26 | PORT WESTWARD | TROJAN #1 | 230.00 | 230.00 | H-WOOD | 8.46 | | 1 |
| 27 | | | 230.00 | 230.00 | ST. MONOP | 10.32 | | 2 |
| 28 | PORT WESTWARD | TROJAN #2 | 230.00 | 230.00 | H-WOOD | 8.46 | | 1 |
| 29 | | | 230.00 | 230.00 | ST. MONOP | | 10.32 | 2 |
| 30 | ROUND BUTTE | GENERATOR #1 | 230.00 | 230.00 | ST. TOWER | 0.54 | | 1 |
| 31 | ROUND BUTTE | GENERATOR #2 | 230.00 | 230.00 | ST. TOWER | 0.54 | | 1 |
| 32 | ROUND BUTTE | GENERATOR #3 | 230.00 | 230.00 | ST. TOWER | 0.54 | | 1 |
| 33 | TOTAL PROJECT 230KV | | | | | 74.60 | 10.32 | 14 |
| 34 | | | | | | | | |
| 35 | BETHEL | McLOUGHLIN | 230.00 | 230.00 | H-WOOD | 35.52 | | 1 |
| 36 | | | | | TOTAL | 1,451.00 | 559.01 | 81 |

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



## TRANSMISSION LINE STATISTICS

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

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH (Pole miles) On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | BETHEL | ROUND BUTTE | 230.00 | 230.00 | H-WOOD | 54.87 | | 1 |
| 2 | | | 230.00 | 230.00 | ST. TOWER | 43.83 | | 1 |
| 3 | BETHEL | SANTIAM BPA | 230.00 | 230.00 | H-WOOD | 3.64 | | 1 |
| 4 | BIG EDDY BPA | McLOUGHLIN | 230.00 | 230.00 | H-WOOD | 0.91 | | 1 |
| 5 | BLUE LAKE | GRESHAM | 230.00 | 230.00 | ST. TOWER | 1.05 | | 1 |
| 6 | | | 230.00 | 230.00 | ST. TOWER | 4.87 | | 2 |
| 7 | BLUE LAKE | TROUTDALE BPA #1 | 230.00 | 230.00 | ST. MONOP | 0.08 | | 1 |
| 8 | | | 230.00 | 230.00 | ST. MONOP | 0.85 | | 2 |
| 9 | | | 230.00 | 230.00 | ST. TOWER | 0.52 | | 2 |
| 10 | BLUE LAKE | TROUTDALE BPA #2 | 230.00 | 230.00 | ST. MONOP | 0.12 | | 1 |
| 11 | | | 230.00 | 230.00 | ST. MONOP | | 0.90 | 2 |
| 12 | | | 230.00 | 230.00 | ST. TOWER | | 0.52 | 2 |
| 13 | CARTLON BPA | SHERWOOD | 230.00 | 230.00 | ST. TOWER | 8.98 | 8.98 | 2 |
| 14 | CARVER | GRESHAM #1 | 230.00 | 230.00 | H-WOOD | 7.39 | | 1 |
| 15 | CARVER | McLOUGHLIN #1 | 230.00 | 230.00 | H-WOOD | 4.04 | | 1 |
| 16 | | | 230.00 | 230.00 | ST. MONOP | 0.88 | | 1 |
| 17 | CARVER | McLOUGHLIN #2 | 230.00 | 230.00 | ST. MONOP | 4.88 | | 1 |
| 18 | GRESHAM | TROUTDALE PACW #1 | 230.00 | 230.00 | H-WOOD | 0.43 | 0.43 | 1 |
| 19 | GRESHAM | TROUTDALE PACW #2 | 230.00 | 230.00 | H-WOOD | 0.26 | | 1 |
| 20 | HORIZON | KEELER BPA | 230.00 | 230.00 | ST. MONOP | 0.79 | | 1 |
| 21 | | | 230.00 | 230.00 | ST. MONOP | 0.68 | | 2 |
| 22 | HORIZON | ST. MARYS - TROJAN | 230.00 | 230.00 | ST. TOWER | 41.24 | | 1 |
| 23 | | | 230.00 | 230.00 | ST. MONOP | 3.96 | | 1 |
| 24 | KEELER BPA | RIVERGATE | 230.00 | 230.00 | ST. TOWER | 0.10 | | 2 |
| 25 | KEELER BPA | ST. MARYS | 230.00 | 230.00 | H-WOOD | 2.87 | | 1 |
| 26 | | | 230.00 | 230.00 | ST. TOWER | 3.80 | | 2 |
| 27 | McLOUGHLIN | PEARL BPA - SHERWOOD | 230.00 | 230.00 | ST. TOWER | 4.57 | | 2 |
| 28 | | | 230.00 | 230.00 | ST. TOWER | 11.67 | | 2 |
| 29 | | | 230.00 | 230.00 | ST. MONOP | 0.14 | | 2 |
| 30 | MURRAYHILL | SHERWOOD #1 | 230.00 | 230.00 | ST. TOWER | | 5.58 | 2 |
| 31 | MURRAYHILL | SHERWOOD #2 | 230.00 | 230.00 | ST. TOWER | 5.58 | | 2 |
| 32 | MURRAYHILL | ST. MARYS | 230.00 | 230.00 | ST. TOWER | 3.07 | | 1 |
| 33 | | | 230.00 | 230.00 | ST. TOWER | 2.15 | | 2 |
| 34 | PEARL BPA | SHERWOOD | 230.00 | 230.00 | ST. MONOP | 0.16 | | 1 |
| 35 | | | 230.00 | 230.00 | ST. TOWER | | 4.19 | 1 |
| 36 | | | | | TOTAL | 1,451.00 | 559.01 | 81 |

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



## TRANSMISSION LINE STATISTICS

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

| Line No. | DESIGNATION From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH (Pole miles) On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | | | 230.00 | 230.00 | H-WOOD | | 0.59 | 1 |
| 2 | REDMOND BPA | ROUND BUTTE | 230.00 | 230.00 | H-WOOD | 23.58 | | 1 |
| 3 | RIVERGATE | ROSS BPA | 230.00 | 230.00 | ST. TOWER | 0.09 | | 2 |
| 4 | RIVERGATE | TROJAN | 230.00 | 230.00 | ST. TOWER | 2.48 | 32.60 | 2 |
| 5 | NON-PROJECT 230KV TOT | | | | | | | |
| 6 | 230KV EXPENSES TOT | | | | | | | |
| 7 | TOTAL 230KV LINES | | | | | 280.05 | 53.79 | 57 |
| 8 | | | | | | | | |
| 9 | ALL 115KV LINES | | | | | 430.06 | | |
| 10 | ALL 57KV LINES | | | | | 11.81 | | |
| 11 | TOT 115KV AND 57 KV | | | | | 441.87 | | |
| 12 | | | | | | | | |
| 13 | | | | | | | | |
| 14 | | | | | | | | |
| 15 | | | | | | | | |
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| 32 | | | | | | | | |
| 33 | | | | | | | | |
| 34 | | | | | | | | |
| 35 | | | | | | | | |
| 36 | | | | | TOTAL | 1,451.00 | 559.01 | 81 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | // | End of 2020/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 | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| (i) | Land (j) | Construction and Other Costs (k) | Total Cost (l) | Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | |
| | | | | | | | | 1 |
| 2-1780 ACSR | | 4,620,708 | 4,620,708 | | | | | 2 |
| 2-1780 ACSR | | 10,214,468 | 10,214,468 | | | | | 3 |
| 2-1780 ACSR | | | | | | | | 4 |
| | | | | | | | | 5 |
| | | | | | | | | 6 |
| | | | | | | | | 7 |
| | | | | | | | | 8 |
| | | | | | | | | 9 |
| | 1,194,326 | 43,101,062 | 44,295,388 | | | | | 10 |
| 2-1780 ACSR | 50,953 | 8,520,018 | 8,570,971 | | | | | 11 |
| 2-1780 ACSR | 275,427 | 15,581,384 | 15,856,811 | | | | | 12 |
| | 5,904 | | 5,904 | | | | | 13 |
| | | 148,889 | 148,889 | | | | | 14 |
| | | 148,889 | 148,889 | | | | | 15 |
| | | 3,624,934 | 3,624,934 | | | | | 16 |
| | | | | 1,198,557 | 482,664 | 521,117 | 2,202,338 | 17 |
| | 1,526,610 | 85,960,352 | 87,486,962 | 1,198,557 | 482,664 | 521,117 | 2,202,338 | 18 |
| | | | | | | | | 19 |
| | | | | | | | | 20 |
| 2156 ACSS | | | | | | | | 21 |
| | | 3,040,852 | 3,040,852 | | | | | 22 |
| 954 ACSR | | 1,956,263 | 1,956,263 | | | | | 23 |
| 795 AAC | | | | | | | | 24 |
| 795 ACSR | 7,579 | 398,550 | 406,129 | | | | | 25 |
| 2156 ACSS | | | | | | | | 26 |
| 2156 ACSS | | | | | | | | 27 |
| 2156 ACSS | | | | | | | | 28 |
| 2156 ACSS | | | | | | | | 29 |
| 795 ACSR | | | | | | | | 30 |
| 795 ACSR | | | | | | | | 31 |
| 795 ACSR | | | | | | | | 32 |
| | 7,579 | 5,395,665 | 5,403,244 | | | | | 33 |
| | | | | | | | | 34 |
| 1272 AAC | | | | | | | | 35 |
| | 10,286,131 | 354,132,656 | 364,418,787 | 3,825,449 | 1,674,830 | 1,326,887 | 6,827,166 | 36 |

TRANSMISSION LINE STATISTICS (Continued)

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

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 1272 ACSR | 293,351 | 6,431,090 | 6,724,441 | | | | | 1 |
| 1272 ACSR | | | | | | | | 2 |
| 795 ACSR | | | | | | | | 3 |
| 1780 ACSR | | | | | | | | 4 |
| 1272 ACSS | | | | | | | | 5 |
| 1272 ACSS | | | | | | | | 6 |
| 1272 ACSS | | | | | | | | 7 |
| 1272 ACSS | | | | | | | | 8 |
| 1272 ACSS | | | | | | | | 9 |
| 1272 ACSS | | | | | | | | 10 |
| 1272 ACSS | | | | | | | | 11 |
| 1272 ACSS | | | | | | | | 12 |
| 1272 AAC | | | | | | | | 13 |
| 1272 AAC | | | | | | | | 14 |
| 1272 AAC | | | | | | | | 15 |
| 1272 AAC | | | | | | | | 16 |
| 1272 ACSS | | | | | | | | 17 |
| 954 ACSR | | | | | | | | 18 |
| 1272 AAC | | | | | | | | 19 |
| 1272 ACSS | | | | | | | | 20 |
| 1272 ACSS | | | | | | | | 21 |
| 1590 AAC | | | | | | | | 22 |
| 1590 AAC | | | | | | | | 23 |
| 1272 AAC | | | | | | | | 24 |
| 1590 ACSR TWD | | | | | | | | 25 |
| 1590 ACSR TWD | | | | | | | | 26 |
| 2-1272 AAC | | | | | | | | 27 |
| 1272 AAC | | | | | | | | 28 |
| 2-1780 ACSR | | | | | | | | 29 |
| 1272 AAC | | | | | | | | 30 |
| 1272 AAC | | | | | | | | 31 |
| 1272 AAC | | | | | | | | 32 |
| 1272 AAC | | | | | | | | 33 |
| 2-2388 AAC TW | | | | | | | | 34 |
| 2-2388 AAC TW | | | | | | | | 35 |
| | 10,286,131 | 354,132,656 | 364,418,787 | 3,825,449 | 1,674,830 | 1,326,887 | 6,827,166 | 36 |

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) | |
| 2-2388 AAC TW | | | | | | | | 1 |
| 795 ACSR | | | | | | | | 2 |
| 795 ACSR | | | | | | | | 3 |
| 1272 AAC | | | | | | | | 4 |
| | 8,307,341 | 108,562,847 | 116,870,188 | | | | | 5 |
| | | | | 444,386 | 151,388 | 802,404 | 1,398,178 | 6 |
| | 8,600,692 | 114,993,937 | 123,594,629 | 444,386 | 151,388 | 802,404 | 1,398,178 | 7 |
| | | | | | | | | 8 |
| | | | | | | | | 9 |
| | | | | | | | | 10 |
| | 151,250 | 147,782,702 | 147,933,952 | 2,182,506 | 1,040,778 | 3,366 | 3,226,650 | 11 |
| | | | | | | | | 12 |
| | | | | | | | | 13 |
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| | | | | | | | | 34 |
| | | | | | | | | 35 |
| | 10,286,131 | 354,132,656 | 364,418,787 | 3,825,449 | 1,674,830 | 1,326,887 | 6,827,166 | 36 |

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report (Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2020/Q4 |
|---|---|---|---|

FOOTNOTE DATA

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

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

**Schedule Page: 422 Line No.: 5 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.: 14 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.: 15 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.: 16 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.: 22 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.: 24 Column: b**

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

**Schedule Page: 422 Line No.: 25 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.: 4 Column: a**

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

**Schedule Page: 422.1 Line No.: 13 Column: a**

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

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

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

**Schedule Page: 422.1 Line No.: 24 Column: a**

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

**Schedule Page: 422.1 Line No.: 34 Column: a**

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

**Schedule Page: 422.2 Line No.: 3 Column: a**

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

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 | GRESHAM | TROUTDALE PACW #2 | 0.26 | WOOD H FRAME | 20.00 | 1 | 1 |
| 2 | BLUE LAKE | MCGILL | 4.03 | WOOD POLE | 25.00 | 1 | 1 |
| 3 | BLUE LAKE | TABOR | 13.34 | WOOD POLE | 20.00 | 1 | 1 |
| 4 | BUTLER | ORENCO | 1.26 | STEEL POLE | 20.00 | 1 | 1 |
| 5 | BUTLER | ST. MARYS | 4.68 | WOOD POLE | 20.00 | 1 | 1 |
| 6 | BUTLER | SUNSET #1 | 1.44 | STEEL POLE | 16.00 | 1 | 1 |
| 7 | BUTLER | SUNSET #2 | 1.49 | STEEL POLE | 16.00 | 1 | 1 |
| 8 | ORENCO | ROSEWAY | 3.00 | WOOD POLE | 20.00 | 1 | 1 |
| 9 | REEDVILLE | ROSEWAY | 1.89 | STEEL POLE | 15.00 | 1 | 1 |
| 10 | ROCK CREEK | SUNSET | 5.26 | WOOD POLE | 20.00 | 1 | 1 |
| 11 | ROCK CREEK | WEST UNION | 2.20 | WOOD POLE | 20.00 | 1 | 1 |
| 12 | | | | | | | |
| 13 | | | | | | | |
| 14 | | | | | | | |
| 15 | | | | | | | |
| 16 | | | | | | | |
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| 43 | | | | | | | |
| 44 | TOTAL | | 38.85 | | 212.00 | 11 | 11 |

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 KV (Operating) (k) | LINE COST | | | | | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| Size (h) | Specification (i) | Configuration and Spacing (j) | | Land and Land Rights (l) | Poles, Towers and Fixtures (m) | Conductors and Devices (n) | Asset Retire. Costs (o) | Total (p) | |
| 1272 AAC | | | 230 | | 121,614 | | | 121,614 | 1 |
| 795 ACSS | | | 115 | | 5,749,462 | 5,749,642 | | 11,499,104 | 2 |
| 795 AAC | | | 115 | | 7,912,764 | 2,496,995 | | 10,409,759 | 3 |
| 1272 ACSS | | | 115 | | 407,220 | 407,220 | | 814,440 | 4 |
| 795 AAC | | | 115 | | 407,220 | 407,220 | | 814,440 | 5 |
| 1272 ACSS | | | 115 | | 407,220 | 407,220 | | 814,440 | 6 |
| 795 AAC | | | 115 | | 407,220 | 407,220 | | 814,440 | 7 |
| 795 AAC | | | 115 | | | | | | 8 |
| 795 AAC | | | 115 | | | | | | 9 |
| 795 AAC | | | 115 | | 1,790,848 | 1,790,848 | | 3,581,696 | 10 |
| 795 AAC | | | 115 | | 1,970,779 | 1,970,779 | | 3,941,558 | 11 |
| | | | | | | | | | 12 |
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| | | | | | 19,174,347 | 13,637,144 | | 32,811,491 | 44 |

## 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 | Amity, near Amity, OR | Distrib./unattended | 57.00 | 13.00 | |
| 4 | Arleta, Portland, OR | Distrib./unattended | 57.00 | 13.00 | |
| 5 | Banks, Banks, Or | Distrib./unattended | 57.00 | 13.00 | |
| 6 | Barnes, Salem, OR | Distrib./unattended | 115.00 | 13.00 | |
| 7 | Boring, near Boring, OR | Distrib./unattended | 57.00 | 13.00 | |
| 8 | Brookwood, near Hillsboro, OR | Distrib./unattended | 57.00 | 13.00 | |
| 9 | Canby, near Barlow, OR | Distrib./unattended | 57.00 | 13.00 | |
| 10 | Cedar Hills, near Beaverton, OR | Distrib./unattended | 115.00 | 13.00 | |
| 11 | Centennial, near Gresham, OR | Distrib./unattended | 115.00 | 13.00 | |
| 12 | Chemawa BPA, near Salem, OR | Distrib./unattended | 115.00 | | |
| 13 | Chemawa BPA, near Salem, OR | Distrib./unattended | 57.00 | | |
| 14 | Claxtar, Salem, OR | Distrib./unattended | 57.00 | 13.00 | |
| 15 | Coffee Creek, Sherwood, OR | Distrib./unattended | 115.00 | 13.00 | |
| 16 | Cornell, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 17 | Dilley, near Forest Grove, OR | Distrib./unattended | 57.00 | 13.00 | |
| 18 | Durham, Tigard, OR | Distrib./unattended | 115.00 | 13.00 | |
| 19 | Eagle Creek, Eagle Creek, OR | Distrib./unattended | 57.00 | 13.00 | |
| 20 | Elma, near Salem, OR | Distrib./unattended | 57.00 | 13.00 | |
| 21 | Estacada, Estacada, OR | Distrib./unattended | 57.00 | 13.00 | |
| 22 | Garden Home, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 23 | Glencoe, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 24 | Harmony, near Milwaukie, OR | Distrib./unattended | 115.00 | 13.00 | |
| 25 | Hayden Island, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 26 | Hemlock, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 27 | Hillsboro, Hillsboro, OR | Distrib./unattended | 57.00 | 13.00 | |
| 28 | Hogan North, Gresham, OR | Distrib./unattended | 115.00 | 13.00 | |
| 29 | Holgate, Portland, OR | Distrib./unattended | 57.00 | 13.00 | |
| 30 | Huber, near Beaverton, OR | Distrib./unattended | 115.00 | 13.00 | |
| 31 | Jennings Lodge, Jennings Lodge, OR | Distrib./unattended | 115.00 | 13.00 | |
| 32 | Kelley Point, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 33 | Leland, Oregon City, OR | Distrib./unattended | 57.00 | 13.00 | |
| 34 | Lents, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 35 | Lents, near Portland, OR | Distrib./unattended | 57.00 | 11.00 | |
| 36 | Main, Hillsboro, OR | Distrib./unattended | 57.00 | 13.00 | |
| 37 | McClain, Salem, OR | Distrib./unattended | 57.00 | 13.00 | |
| 38 | Middle Grove, near Middle Grove, OR | Distrib./unattended | 115.00 | 13.00 | |
| 39 | Midway, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 40 | Mobile sub No. 1, OR | Distrib./unattended | 115.00 | 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<br>(2) [ ] A Resubmission | 04/16/2021 | End of 2020/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 | Mobile sub No. 2, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 2 | Mobile Sub No. 3, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 3 | Mobile Sub No. 4, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 4 | Mobile Sub No. 5, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 5 | Mobile Sub No. 6, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 6 | Mobile Sub No. 7, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 7 | Mobile Sub No. 8, 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 | North Marion, near Woodburn, OR | Distrib./unattended | 57.00 | 13.00 | |
| 13 | North Plains, North Plains, OR | Distrib./unattended | 57.00 | 13.00 | |
| 14 | Northern, Portland, OR | Distrib./unattended | 57.00 | 11.00 | |
| 15 | Oak Hills, near Beaverton, OR | Distrib./unattended | 115.00 | 13.00 | |
| 16 | Oregon City - BPA, near Wilsonville, OR | Distrib./unattended | 57.00 | | |
| 17 | Orient, near Gresham, OR | Distrib./unattended | 57.00 | 13.00 | |
| 18 | Peninsula Park, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 19 | Raleigh Hills, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 20 | Ramapo, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 21 | Redland, near Oregon City, OR | Distrib./unattended | 115.00 | 13.00 | |
| 22 | Rhododendron Switching, OR | Distrib./unattended | 57.00 | | |
| 23 | Riverview, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 24 | Rockwood, near Gresham, OR | Distrib./unattended | 115.00 | 13.00 | |
| 25 | Roseway, Hillsboro, OR | Distrib./unattended | 115.00 | 13.00 | |
| 26 | Salem-PGE, near Salem, OR | Distrib./unattended | 57.00 | 13.00 | |
| 27 | Sandy, Sandy, OR | Distrib./unattended | 57.00 | 13.00 | |
| 28 | Scoggins, near Gaston, OR | Distrib./unattended | 57.00 | 13.00 | |
| 29 | Sheridan, Sheridan, OR | Distrib./unattended | 57.00 | 13.00 | |
| 30 | Silverton, Silverton, OR | Distrib./unattended | 57.00 | 13.00 | |
| 31 | Springdale, near Springdale, OR | Distrib./unattended | | 12.50 | |
| 32 | St. Johns-BPA, near Portland, OR | Distrib./unattended | | 11.00 | |
| 33 | St. Louis, Gevais, OR | Distrib./unattended | 57.00 | 13.00 | |
| 34 | Summit, Government Camp, OR | Distrib./unattended | 57.00 | 13.00 | |
| 35 | Summit, Government Camp, OR | Distrib./unattended | 24.00 | 13.00 | |
| 36 | Swan Island, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 37 | Sylvan, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 38 | Tigard, Tigard, OR | Distrib./unattended | 115.00 | 13.00 | |
| 39 | Twilight, Canby, OR | Distrib./unattended | 57.00 | 13.00 | |
| 40 | Waconda, near Hopmere, OR | Distrib./unattended | 57.00 | 13.00 | |

SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | Wallace, Salem, OR | Distrib./unattended | 57.00 | 13.00 | |
| 2 | Welches, near Welches, OR | Distrib./unattended | 57.00 | 24.00 | |
| 3 | Welches, near Welches, OR | Distrib./unattended | 57.00 | 13.00 | |
| 4 | Willamina, near Willamina, OR | Distrib./unattended | 57.00 | 13.00 | |
| 5 | Willbridge, Portland, OR | Distrib./unattended | 115.00 | 11.00 | |
| 6 | Woodburn, Woodburn, OR | Distrib./unattended | 57.00 | 13.00 | |
| 7 | Yamhill, near Yamhill, OR | Distrib./unattended | 57.00 | 13.00 | |
| 8 | | | | | |
| 9 | | | | | |
| 10 | Alder, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 11 | Beaverton, Beaverton, OR | T&D/unattended | 115.00 | 13.00 | |
| 12 | Bell, near Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 13 | Bethany, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 14 | Bethel, Salem, OR | T&D/unattended | 230.00 | 115.00 | 13.00 |
| 15 | Bethel, Salem, OR | T&D/unattended | 115.00 | 57.00 | 13.00 |
| 16 | Bethel, Salem ,OR | T&D/unattended | 115.00 | 13.00 | |
| 17 | Blue Lake, Troutdale, OR | T&D/unattended | 230.00 | 115.00 | 13.00 |
| 18 | Blue Lake, Troutdale, OR | T&D/unattended | 115.00 | 13.00 | |
| 19 | Boones Ferry, Lake Oswego, OR | T&D/unattended | 115.00 | 13.00 | |
| 20 | Butler, Hillsboro, OR | T&D/unattended | 115.00 | 13.00 | |
| 21 | Canemah, Oregon City, OR | T&D/unattended | 115.00 | 57.00 | 13.00 |
| 22 | Canyon, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 23 | Carver, Carver, OR | T&D/unattended | 230.00 | 115.00 | 13.00 |
| 24 | Carver, Carver, OR | T&D/unattended | 115.00 | 13.00 | |
| 25 | Clackamas, Clackamas, OR | T&D/unattended | 115.00 | 13.00 | |
| 26 | Cornelius, Cornelius, OR | T&D/unattended | 115.00 | 57.00 | 13.00 |
| 27 | Cornelius, Cornelius, OR | T&D/unattended | 57.00 | 13.00 | |
| 28 | Culver, Salem, OR | T&D/unattended | 115.00 | 13.00 | |
| 29 | Curtis, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 30 | Dayton, near Dayton, OR | T&D/unattended | 115.00 | 57.00 | 13.00 |
| 31 | Dayton, near Dayton, OR | T&D/unattended | 57.00 | 13.00 | |
| 32 | Delaware, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 33 | Denny, Beaverton, OR | T&D/unattended | 115.00 | 13.00 | |
| 34 | Dunn's Corner, near Sandy, OR | T&D/unattended | 57.00 | 13.00 | |
| 35 | E., Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 36 | E., Portland, OR | T&D/unattended | 115.00 | 11.00 | |
| 37 | Eastport, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 38 | Fairmount, Salem, OR | T&D/unattended | 115.00 | 13.00 | |
| 39 | Fairview, Fairview OR | T&D/unattended | 115.00 | 13.00 | |
| 40 | Faraday Plant, near Estacada, OR | T&D/unattended | 115.00 | 13.00 | |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2020/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.
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| Line No. | Name and Location of Substation | Character of Substation | VOLTAGE (In MVa) | | |
|---|---|---|---|---|---|
| | | | Primary | Secondary | Tertiary |
| | (a) | (b) | (c) | (d) | (e) |
| 1 | Faraday, Switchyard, OR | T&D/unattended | 115.00 | 57.00 | 13.00 |
| 2 | Faraday, Switchyard, OR | T&D/unattended | 57.00 | 11.00 | |
| 3 | Glencullen, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 4 | Glendoveer, near Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 5 | Glisan, Gresham, OR | T&D/unattended | 115.00 | 13.00 | |
| 6 | Grand Ronde, Grand Ronde, OR | T&D/unattended | 115.00 | 57.00 | 13.00 |
| 7 | Grand Ronde, Grand Ronde, OR | T&D/unattended | 115.00 | 13.00 | |
| 8 | Harborton, near Portland, OR | T&D/unattended | 230.00 | 115.00 | 13.00 |
| 9 | Harborton, near Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 10 | Harrison Sub, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 11 | Hillcrest, Salem, OR | T&D/unattended | 115.00 | 13.00 | |
| 12 | Hogan South, Gresham, OR | T&D/unattended | 115.00 | 57.00 | 13.00 |
| 13 | Hogan South, Gresham, OR | T&D/unattended | 115.00 | 13.00 | |
| 14 | Indian, near Salem, OR | T&D/unattended | 115.00 | 13.00 | |
| 15 | Island, near Milwaukie, OR | T&D/unattended | 115.00 | 13.00 | |
| 16 | Kelly Butte, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 17 | King City, King City, OR | T&D/unattended | 115.00 | 13.00 | |
| 18 | Liberty, Salem, OR | T&D/unattended | 115.00 | 13.00 | |
| 19 | Market, Salem, OR | T&D/unattended | 115.00 | 13.00 | |
| 20 | Marquam, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 21 | McGill, Gresham, OR | T&D/unattended | 115.00 | 13.00 | |
| 22 | McLoughlin, near Oregon City, OR | T&D/unattended | 230.00 | 115.00 | 13.00 |
| 23 | Meridian, near Tualatin, OR | T&D/unattended | 115.00 | 13.00 | |
| 24 | Mill Creek, near Salem, OR | T&D/unattended | 115.00 | 13.00 | |
| 25 | Monitor, near Monitor, OR | T&D/unattended | 230.00 | 57.00 | 13.00 |
| 26 | Murrayhill, Beaverton, OR | T&D/unattended | 115.00 | 13.00 | |
| 27 | Murrayhill, Beaverton, OR | T&D/unattended | 230.00 | 115.00 | 13.00 |
| 28 | Newberg, Newberg, OR | T&D/unattended | 115.00 | 13.00 | |
| 29 | Oak Grove, Three Lynx, OR | T&D/unattended | 115.00 | 13.00 | |
| 30 | Oak Grove, Three Lynx, OR | T&D/unattended | 115.00 | 11.00 | |
| 31 | Oak Grove, Three Lynx, OR | T&D/unattended | 13.00 | 11.00 | |
| 32 | Oak Grove, Three Lynx, OR | T&D/unattended | 13.00 | 0.48 | |
| 33 | Orenco, near Hillsboro, OR | T&D/unattended | 115.00 | 57.00 | 13.00 |
| 34 | Orenco, near Hillsboro, OR | T&D/unattended | 115.00 | 13.00 | |
| 35 | Oswego, Lake Oswego, OR | T&D/unattended | 115.00 | 13.00 | |
| 36 | Oxford, Salem, OR | T&D/unattended | 115.00 | 13.00 | |
| 37 | Pleasant Valley, near Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 38 | Portsmouth, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 39 | Progress, near Tigard, OR | T&D/unattended | 115.00 | 13.00 | |
| 40 | Reedville, near Beaverton, OR | T&D/unattended | 115.00 | 13.00 | |

SUBSTATIONS

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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 | River Mill, near Beaverton, OR | T&D/unattended | 57.00 | 11.00 | |
| 2 | Rivergate North Yard, Portland, OR | T&D/unattended | 230.00 | 115.00 | 13.00 |
| 3 | Rivergate South Yard, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 4 | Rivergate South Yard, Portland, OR | T&D/unattended | 115.00 | 11.00 | |
| 5 | Rock Creek, near Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 6 | Rosemont, near Lake Oswego, OR | T&D/unattended | 115.00 | 13.00 | |
| 7 | Round Butte, near Madras, OR | T&D/unattended | 500.00 | 230.00 | 12.00 |
| 8 | Round Butte, near Madras, OR | T&D/unattended | 230.00 | 13.00 | |
| 9 | Ruby, Gresham, OR | T&D/unattended | 115.00 | 13.00 | |
| 10 | Scappose, Scappose, OR | T&D/unattended | 115.00 | | |
| 11 | Scholls Ferry, Beaverton, OR | T&D/unattended | 115.00 | 13.00 | |
| 12 | Sellwood, Portland, OR | T&D/unattended | 115.00 | 57.00 | 13.00 |
| 13 | Sellwood, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 14 | Shute, Hillsboro, OR | T&D/unattended | 115.00 | 34.50 | |
| 15 | Six Corners, Six Corners, OR | T&D/unattended | 115.00 | 13.00 | |
| 16 | Springbrook, Newberg, OR | T&D/unattended | 115.00 | 13.00 | |
| 17 | St. Helens, near St. Helens, OR | T&D/unattended | 115.00 | | |
| 18 | St. Marys, West Yard, Beaverton, OR | T&D/unattended | 230.00 | 115.00 | 13.00 |
| 19 | St. Marys, East Yard, Beaverton, OR | T&D/unattended | 115.00 | 13.00 | |
| 20 | Sullivan, West Linn, OR | T&D/unattended | 115.00 | 13.00 | |
| 21 | Sullivan, West Linn, OR | T&D/unattended | 57.00 | 4.15 | |
| 22 | Sunset, near Hillsboro, OR | T&D/unattended | 115.00 | 13.00 | |
| 23 | Sunset, near Hillsboro, OR | T&D/unattended | 115.00 | 34.50 | |
| 24 | Tabor, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 25 | Tabor, Portland, OR | T&D/unattended | 57.00 | | |
| 26 | Tektronix, Beaverton, OR | T&D/unattended | 115.00 | 13.00 | |
| 27 | Town Center, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 28 | Trojan, near Rainier, OR | T&D/unattended | 230.00 | 13.00 | |
| 29 | Tualatin, Tualatin, OR | T&D/unattended | 115.00 | 13.00 | |
| 30 | University, Salem, OR | T&D/unattended | 115.00 | 13.00 | |
| 31 | Urban, Portland, OR | T&D/unattended | 115.00 | 13.00 | |
| 32 | West Portland, Lower Yard, Tigard, OR | T&D/unattended | 115.00 | | |
| 33 | West Portland, Upper Yard, Tigard, OR | T&D/unattended | 115.00 | 13.00 | |
| 34 | West Union, near Hillsboro, OR | T&D/unattended | 115.00 | 13.00 | |
| 35 | Willsonville, near Willsonville ,OR | T&D/unattended | 115.00 | 13.00 | |
| 36 | | | | | |
| 37 | | | | | |
| 38 | Bakeoven, BPA, near Bakeoven, OR | Transm./unattended | 500.00 | | |
| 39 | Beaver Plant, near Clatskanie, OR | Transm./unattended | 230.00 | 13.00 | |
| 40 | Beaver Plant, near Clatskanie, OR | Transm./unattended | 230.00 | 24.00 | |

SUBSTATIONS

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

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | Biglow Canyon Wind Farm, Wasco, OR | Transm./unattended | 230.00 | 34.50 | 13.00 |
| 2 | Boardman, near Boardman, OR | Transm./unattended | 500.00 | 24.00 | |
| 3 | Boardman, OR | Transm./unattended | 230.00 | 7.20 | |
| 4 | Boardman, OR | Transm./unattended | 24.00 | 7.20 | |
| 5 | Broadview Subst. near Broadview, MT | Transm./unattended | 500.00 | 230.00 | |
| 6 | Buckley, BPA near Buckley, WA | Transm./unattended | 500.00 | | |
| 7 | Captain Jack, BPA, near Malin, OR | Transm./unattended | 500.00 | | |
| 8 | Carty, near Boardman, OR | Transm./unattended | 500.00 | 21.00 | |
| 9 | Carty, near Boardman, OR | Transm./unattended | 16.00 | 7.20 | 4.20 |
| 10 | Colstrip Plant, near Colstrip, MT | Transm./unattended | 500.00 | 26.00 | |
| 11 | Colstrip Subst. near Colstrip, MT | Transm./unattended | 500.00 | 230.00 | |
| 12 | Coyote Springs, Boardman, OR | Transm./unattended | 500.00 | | |
| 13 | Forest Grove, Forest Grove, OR | Transm./unattended | 115.00 | | |
| 14 | Fort Rock, approx 12 mi NE of Silver Lake, OR | Transm./unattended | 500.00 | | |
| 15 | Grassland, near Boardman, OR | Transm./unattended | 500.00 | | |
| 16 | Gresham, near Gresham, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 17 | Grizzly, BPA, near Madras, OR | Transm./unattended | 500.00 | | |
| 18 | Horizon, Hillsboro, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 19 | Keeler, BPA, Hillsboro, OR | | | | |
| 20 | Linneman, near Gresham, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 21 | Malin, BPA, near Malin, OR | Transm./unattended | 500.00 | | |
| 22 | North Fork, near Estacada, OR | Transm./unattended | 115.00 | 13.00 | 0.48 |
| 23 | Pearl, BPA, near Wilsonville, OR | Transm./unattended | 230.00 | | |
| 24 | Pelton, near Madras, OR | Transm./unattended | 230.00 | 13.00 | |
| 25 | Pelton, near Madras, OR | Transm./unattended | 13.00 | 13.00 | |
| 26 | Port Westward, near Clatskanie, OR | Transm./unattended | 230.00 | 18.00 | |
| 27 | Port Westward, near Clatskanie, OR | Transm./unattended | 13.00 | 4.20 | |
| 28 | Sand Springs, 22 mi E/22 mi S of Bend, OR | Transm./unattended | 500.00 | | |
| 29 | Sherwood, near Six Corners, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 30 | Slatt, BPA, Arlington, OR | Transm./unattended | 500.00 | | |
| 31 | Sycan, 27 mi S of Silver Lake, OR | Transm./unattended | 500.00 | | |
| 32 | Troutdale, BPA near Troutdale OR | Transm./unattended | 230.00 | | |
| 33 | Tucannon Mullan Switchyard, Dayton, WA | Transm./unattended | 230.00 | 34.50 | 13.00 |
| 34 | TOTAL MVa | | 31707.00 | 5408.93 | 432.68 |
| 35 | | | | | |
| 36 | | | | | |
| 37 | | | | | |
| 38 | | | | | |
| 39 | | | | | |
| 40 | | | | | |

SUBSTATIONS (Continued)

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

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 69 | 9 | | Capacitor Banks | 3 | 16 | 1 |
| 45 | 2 | | Capacitor Banks | 4 | 12 | 2 |
| 15 | 2 | | | | | 3 |
| 42 | 2 | | Capacitor Banks | 2 | 7 | 4 |
| 20 | 1 | | Capacitor Banks | 2 | 3 | 5 |
| 42 | 2 | | Capacitor Banks | 2 | 6 | 6 |
| 24 | 2 | | Capacitor Banks | 1 | 12 | 7 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 8 |
| 39 | 4 | | | | | 9 |
| 56 | 2 | | Capacitor Banks | 4 | 13 | 10 |
| 56 | 2 | | Capacitor Banks | 4 | 12 | 11 |
| | | | | | | 12 |
| | | | | | | 13 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 14 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 15 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 16 |
| 13 | 1 | | Capacitor Banks | 3 | 9 | 17 |
| 56 | 2 | | Capacitor Banks | 4 | 13 | 18 |
| 14 | 1 | | | | | 19 |
| 56 | 2 | | Capacitor Banks | 4 | 12 | 20 |
| 30 | 2 | | Capacitor Banks | 2 | 4 | 21 |
| 28 | 1 | | | | | 22 |
| 25 | 1 | | Capacitor Banks | 2 | 6 | 23 |
| 50 | 2 | | Capacitor Banks | 4 | 12 | 24 |
| 34 | 2 | | Capacitor Banks | 4 | 12 | 25 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 26 |
| 43 | 2 | | Capacitor Banks | 4 | 14 | 27 |
| 56 | 2 | | Capacitor Banks | 4 | 12 | 28 |
| 39 | 2 | | Capacitor Banks | 2 | 7 | 29 |
| 56 | 2 | | Capacitor Banks | 2 | 6 | 30 |
| 53 | 2 | | | | | 31 |
| 56 | 2 | | Capacitor Banks | 4 | 12 | 32 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 33 |
| 22 | 1 | | | | | 34 |
| 20 | 2 | | | | | 35 |
| 84 | 3 | | Capacitor Banks | 6 | 20 | 36 |
| 23 | 3 | | | | | 37 |
| 53 | 2 | | Capacitor Banks | 4 | 12 | 38 |
| 34 | 2 | | Capacitor Banks | 1 | 4 | 39 |
| 15 | 1 | | | | | 40 |

SUBSTATIONS (Continued)

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

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 34 | 1 | | | | | 1 |
| 29 | 1 | | | | | 2 |
| 34 | 1 | | | | | 3 |
| 34 | 1 | | | | | 4 |
| 34 | 1 | | | | | 5 |
| 25 | 1 | | | | | 6 |
| 25 | 1 | | | | | 7 |
| 42 | 2 | | Capacitor Banks | 4 | 9 | 8 |
| 20 | 1 | | Capacitor Banks | 3 | 15 | 9 |
| 45 | 2 | | Capacitor Banks | | | 10 |
| 39 | 2 | | Capacitor Banks | 3 | 10 | 11 |
| 31 | 3 | | Capacitor Banks | 3 | 15 | 12 |
| 20 | 1 | | Capacitor Banks | 4 | 18 | 13 |
| 28 | 2 | | | | | 14 |
| 56 | 2 | | Capacitor Banks | 4 | 14 | 15 |
| | | | | | | 16 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 17 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 18 |
| 28 | 1 | | Capacitor Banks | 2 | 7 | 19 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 20 |
| 22 | 1 | | | | | 21 |
| | | | | | | 22 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 23 |
| 78 | 3 | | Capacitor Banks | 5 | 15 | 24 |
| 28 | 1 | 1 | Capacitor Banks | 2 | 6 | 25 |
| 45 | 2 | | Capacitor Banks | 4 | 12 | 26 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 27 |
| 13 | 2 | | Capacitor Banks | 1 | 11 | 28 |
| 17 | 1 | | Capacitor Banks | 3 | 16 | 29 |
| 42 | 2 | | | | | 30 |
| | | | | | | 31 |
| | | | | | | 32 |
| 24 | 2 | | Capacitor Banks | 2 | 7 | 33 |
| 8 | 1 | | | | | 34 |
| 14 | 1 | | | | | 35 |
| 53 | 2 | | Capacitor Banks | 4 | 12 | 36 |
| 22 | 1 | | Capacitor Banks | 2 | 6 | 37 |
| 45 | 2 | | Capacitor Banks | 4 | 12 | 38 |
| 28 | 1 | 1 | Capacitor Banks | 3 | 19 | 39 |
| 41 | 2 | | Capacitor Banks | 2 | 6 | 40 |

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



SUBSTATIONS (Continued)

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

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 28 | 1 | 1 | Capacitor Banks | 2 | 6 | 1 |
| 10 | 1 | | Capacitor Banks | 1 | 12 | 2 |
| 18 | 2 | | Capacitor Banks | 2 | 6 | 3 |
| 31 | 2 | | Capacitor Banks | 2 | 8 | 4 |
| 20 | 1 | | | | | 5 |
| 42 | 2 | | Capacitor Banks | 4 | 13 | 6 |
| 15 | 2 | | Capacitor Banks | 1 | 2 | 7 |
| | | | | | | 8 |
| | | | | | | 9 |
| 56 | 2 | | Capacitor Banks | 2 | 6 | 10 |
| 34 | 2 | | Capacitor Banks | 4 | 12 | 11 |
| 66 | 3 | | Capacitor Banks | 4 | 12 | 12 |
| 56 | 2 | | Capacitor Banks | 5 | 15 | 13 |
| 564 | 2 | | | | | 14 |
| 140 | 1 | | | | | 15 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 16 |
| 640 | 2 | | | | | 17 |
| 56 | 2 | | Capacitor Banks | 2 | 6 | 18 |
| 50 | 2 | | Capacitor Banks | 2 | 7 | 19 |
| 300 | 2 | | Capacitor Banks | 8 | 75 | 20 |
| 250 | 6 | | | | | 21 |
| 200 | 4 | | Capacitor Banks | 8 | 29 | 22 |
| 640 | 2 | | | | | 23 |
| 56 | 2 | | Capacitor Banks | 4 | 12 | 24 |
| 41 | 2 | | Capacitor Banks | 4 | 13 | 25 |
| 140 | 1 | | | | | 26 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 27 |
| 28 | 1 | | | | | 28 |
| 17 | 1 | | Capacitor Banks | 2 | 6 | 29 |
| 125 | 1 | | | | | 30 |
| 20 | 2 | | Capacitor Banks | 4 | 6 | 31 |
| 28 | 1 | | | | | 32 |
| 56 | 2 | | Capacitor Banks | 2 | 6 | 33 |
| 14 | 1 | | Capacitor Banks | 2 | 3 | 34 |
| 208 | 5 | | Capacitor Banks | 4 | 29 | 35 |
| 132 | 4 | | Capacitor Banks | 2 | 32 | 36 |
| 17 | 1 | | | | | 37 |
| 25 | 1 | | Capacitor Banks | 1 | 4 | 38 |
| 50 | 2 | | Capacitor Banks | 1 | 3 | 39 |
| 27 | 1 | | | | | 40 |

SUBSTATIONS (Continued)

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

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 140 | 1 | | | | | 1 |
| 32 | 2 | | | | | 2 |
| 24 | 1 | | Capacitor Banks | 2 | 6 | 3 |
| 50 | 2 | | Capacitor Banks | 4 | 12 | 4 |
| 45 | 2 | | Capacitor Banks | 4 | 12 | 5 |
| 33 | 1 | 1 | | | | 6 |
| 13 | 1 | | Capacitor Banks | 2 | 3 | 7 |
| 320 | 1 | | | | | 8 |
| 50 | 2 | | Capacitor Banks | 6 | 19 | 9 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 10 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 11 |
| 125 | 3 | | | | | 12 |
| 56 | 2 | | Capacitor Banks | 4 | 12 | 13 |
| 56 | 2 | | Capacitor Banks | 3 | 11 | 14 |
| 45 | 2 | | Capacitor Banks | 4 | 12 | 15 |
| 45 | 2 | | Capacitor Banks | 2 | 6 | 16 |
| 56 | 2 | | Capacitor Banks | 4 | 12 | 17 |
| 50 | 2 | | Capacitor Banks | 3 | 10 | 18 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 19 |
| 250 | 5 | | Capacitor Banks | 10 | 54 | 20 |
| 75 | 3 | | Capacitor Banks | 6 | 18 | 21 |
| 640 | 2 | | | | | 22 |
| 84 | 3 | | Capacitor Banks | 6 | 19 | 23 |
| 17 | 1 | | Capacitor Banks | 2 | 6 | 24 |
| 125 | 1 | | | | | 25 |
| 56 | 2 | | Capacitor Banks | 3 | 11 | 26 |
| 320 | 1 | | | | | 27 |
| 45 | 2 | | Capacitor Banks | 4 | 12 | 28 |
| 8 | 1 | | | | | 29 |
| 64 | 2 | | | | | 30 |
| | | | | | | 31 |
| | | | | | | 32 |
| 280 | 2 | 1 | Capacitor Banks | 6 | 18 | 33 |
| 81 | 3 | | | | | 34 |
| 34 | 2 | | Capacitor Banks | 2 | 7 | 35 |
| 50 | 2 | | Capacitor Banks | 4 | 12 | 36 |
| 56 | 2 | | Capacitor Banks | 4 | 12 | 37 |
| 28 | 1 | | | | | 38 |
| 50 | 2 | | Capacitor Banks | 4 | 14 | 39 |
| 84 | 3 | | Capacitor Banks | 6 | 18 | 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. |
|---|---|---|---|---|---|---|
| 32 | 2 | | | | | 1 |
| 520 | 4 | 1 | Capacitor Banks | 1 | 24 | 2 |
| 22 | 1 | | Capacitor Banks | 2 | 7 | 3 |
| 22 | 1 | | Capacitor Banks | 2 | 7 | 4 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 5 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 6 |
| 561 | 3 | | Reactors | 12 | 180 | 7 |
| 394 | 4 | 2 | | | | 8 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 9 |
| | | | | | | 10 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 11 |
| 140 | 1 | | Capacitor Banks | 1 | 24 | 12 |
| 28 | 1 | | Capacitor Banks | 2 | 6 | 13 |
| 100 | 2 | 1 | Capacitor Banks | 4 | 18 | 14 |
| 49 | 2 | | Capacitor Banks | 2 | 6 | 15 |
| 56 | 2 | | Capacitor Banks | 5 | 36 | 16 |
| | | | Capacitor Banks | 1 | 24 | 17 |
| 960 | 3 | | Capacitor Banks | 3 | 108 | 18 |
| 56 | 2 | | Capacitor Banks | 4 | 12 | 19 |
| 45 | 2 | | Capacitor Banks | 4 | 12 | 20 |
| 33 | 1 | | | | | 21 |
| 400 | 8 | | Capacitor Banks | 25 | 150 | 22 |
| 375 | 3 | | | | | 23 |
| 22 | 1 | | Capacitor Banks | 2 | 6 | 24 |
| | | | | | | 25 |
| 84 | 3 | | Capacitor Banks | 6 | 18 | 26 |
| 56 | 2 | | Capacitor Banks | 2 | 6 | 27 |
| 56 | 2 | | | | | 28 |
| 56 | 2 | | Capacitor Banks | 4 | 13 | 29 |
| 22 | 1 | | Capacitor Banks | 2 | 7 | 30 |
| 112 | 4 | | Capacitor Banks | 5 | 16 | 31 |
| | | | Capacitor Banks | 1 | 24 | 32 |
| 56 | 2 | | Capacitor Banks | 4 | 13 | 33 |
| 56 | 2 | | Capacitor Banks | 4 | 12 | 34 |
| 84 | 3 | | Capacitor Banks | 6 | 18 | 35 |
| | | | | | | 36 |
| | | | | | | 37 |
| | | | | | | 38 |
| 464 | 4 | 1 | | | | 39 |
| 170 | 1 | | | | | 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<br>(2) [ ] A Resubmission | // | End of 2020/Q4 |



SUBSTATIONS (Continued)

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

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 480 | 3 | | | | | 1 |
| 685 | 3 | 1 | | | | 2 |
| 55 | 1 | | | | | 3 |
| 55 | 1 | | | | | 4 |
| 80 | 3 | | | | | 5 |
| | | | | | | 6 |
| | | | | | | 7 |
| 596 | 2 | 1 | | | | 8 |
| 22 | 1 | | | | | 9 |
| 164 | 3 | | | | | 10 |
| 100 | 2 | | | | | 11 |
| 300 | 3 | 1 | | | | 12 |
| | | | | | | 13 |
| | | | Series Capacitor | 1 | 363 | 14 |
| | | | | | | 15 |
| 572 | 2 | | | | | 16 |
| | | | | | | 17 |
| 640 | 2 | | | | | 18 |
| | | | | | | 19 |
| 168 | 1 | | | | | 20 |
| | | | Reactors | 3 | 180 | 21 |
| 53 | 3 | 1 | | | | 22 |
| | | | | | | 23 |
| 120 | 3 | 1 | | | | 24 |
| 3 | 1 | | | | | 25 |
| 900 | 3 | 1 | | | | 26 |
| 40 | 2 | | | | | 27 |
| | | | Series Capacitor | 1 | 546 | 28 |
| 640 | 2 | | | | | 29 |
| | | | | | | 30 |
| | | | Series Capacitor | 1 | 546 | 31 |
| | | | | | | 32 |
| 320 | 2 | | Capacitors/Reactors | 6 | 90 | 33 |
| 21543 | 386 | 16 | | 451 | 3,677 | 34 |
| | | | | | | 35 |
| | | | | | | 36 |
| | | | | | | 37 |
| | | | | | | 38 |
| | | | | | | 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<br>(2) __ A Resubmission | / / | 2020/Q4 |

FOOTNOTE DATA

**Schedule Page: 426 Line No.: 12 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.: 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: 426.1 Line No.: 16 Column: a**

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

**Schedule Page: 426.1 Line No.: 22 Column: a**

Switching only.

**Schedule Page: 426.1 Line No.: 31 Column: a**

Regulating only.

**Schedule Page: 426.1 Line No.: 32 Column: a**

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

**Schedule Page: 426.4 Line No.: 7 Column: a**

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 76% share of the jointly owned capacity. 100% of the capacity is reported.

**Schedule Page: 426.4 Line No.: 8 Column: a**

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 76% share of the jointly owned capacity. 100% of the capacity is reported.

**Schedule Page: 426.4 Line No.: 10 Column: a**

Switching only. Distribution owned by Columbia River PUD.

**Schedule Page: 426.4 Line No.: 17 Column: a**

Switching only. Distribution owned by Columbia River PUD.

**Schedule Page: 426.4 Line No.: 25 Column: a**

Switching only

**Schedule Page: 426.4 Line No.: 32 Column: a**

Switching only

**Schedule Page: 426.4 Line No.: 38 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.: 2 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: 426.5 Line No.: 3 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: 426.5 Line No.: 4 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: 426.5 Line No.: 5 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: 426.5 Line No.: 6 Column: a**

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

**Schedule Page: 426.5 Line No.: 7 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.: 10 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: 426.5 Line No.: 11 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: 426.5 Line No.: 12 Column: a***

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

***Schedule Page: 426.5 Line No.: 13 Column: a***

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

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

Line compensation only.

***Schedule Page: 426.5 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: 426.5 Line No.: 19 Column: a***

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

***Schedule Page: 426.5 Line No.: 21 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.: 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.

***Schedule Page: 426.5 Line No.: 24 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.: 25 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.: 28 Column: a***

Line compensation only.

***Schedule Page: 426.5 Line No.: 30 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.: 31 Column: a***

Line compensation only.

***Schedule Page: 426.5 Line No.: 32 Column: a***

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2020/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 | 8,521,304 |
| 4 | OPUC Order No. 18-823 | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
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| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | **Non-power Goods or Services Provided for Affiliate** | | | |
| 21 | | | | |
| 22 | Administrative Services | Salmon Springs Hospitality Group | 186 | 934,198 |
| 23 | Administrative Services | 121 SW Salmon Street Corp | 146 | 1,622,181 |
| 24 | | | | |
| 25 | | | | |
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| 27 | | | | |
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Schedule Page No.

## INDEX (continued)

Schedule | Page No.

Document Content(s)

Portland General Electric

# 2020 Annual Report

PGE

# Letter From Our Chief Executive Officer

Maria M. Pope
**President and Chief Executive Officer**

## TO OUR SHAREHOLDERS

2020 was a year unlike any other in Portland General Electric's more than 130-year history. It brought crises that impacted Oregonians, businesses, the economy and climate. I am proud of how our employees rose to meet every challenge, while providing customers with reliable, safe, affordable, clean energy. Despite our challenges, we delivered solid operational results and continued momentum consistent with our long-term growth strategy. Given the energy trading losses, our financial results were disappointing, but we improved operational efficiency and controlled expenses by leveraging technology as we learned to work through the pandemic.

## YEAR IN REVIEW & STRATEGIC ACCOMPLISHMENTS

PGE faced last year's energy trading losses in August and devastating wildfire season crises head-on. Our board and leadership team acted transparently and swiftly to address the trading losses. We did not seek regulatory recovery to ensure that customer prices would not be impacted, and we strengthened internal policies and risk management reporting structures. As wildfires ravaged Oregon last year, we proactively issued a public safety power shutoff in high-risk fire zones and partnered with first responders and state and local officials to de-energize eight additional at-risk areas. Safety is our highest priority, and we are grateful to our government and agency partners as these events take all of us working together.

We are proud of the progress made in 2020 in delivering on our purpose and building Oregon's clean energy future, including the following milestones:

- By 2030, we aim to meet customers' expectations and reduce greenhouse gas emissions associated with the power we deliver by 80%. We are also setting an aspirational goal of zero greenhouse gas emissions associated with the electricity we deliver to customers by 2040.
- In partnership with a subsidiary of NextEra Energy Resources LLC, we brought renewable and reliable energy together with the opening of Eastern Oregon's new Wheatridge Renewable Energy Facility, one of the nation's first facilities to integrate solar and wind generation with battery storage in one location.
- We closed our coal-fired Boardman plant, capping off a decade of diligent planning.
- We announced partnerships with Douglas County Public Utility District and AVANGRID that optimize the region's resources in support of clean energy for customers, while also helping PGE meet our near-term capacity needs.
- We are electrifying Oregon's transportation sector by electrifying our own fleet, developing charging infrastructure for electric vehicles (EVs) and helping customers electrify every aspect of their businesses.
- We were included in the Bloomberg Gender-Equality Index and achieved a perfect score on the Human Rights Campaign Foundation's Corporate Equality

(1) Management believes that excluding the effects of the previously disclosed energy trading losses provides a meaningful representation of the Company's comparative earnings per share. The Company has adjusted this amount to maintain comparability between periods. The net income impact of the energy trading losses was $92 million after tax, and the earnings per diluted share impact was $1.03.

Index, reflecting our ongoing dedication to creating a diverse, equitable and inclusive workplace.

- For the 11th year in a row, PGE has the No. 1 voluntary renewable energy program in the U.S.
- PGE, employees, retirees and the PGE Foundation donated $5.6 million and volunteered 18,200 hours with more than 400 nonprofit organizations across Oregon.

## FINANCIAL PERFORMANCE

Our 2020 GAAP net income was $155 million, or $1.72 per diluted share. Excluding the third-quarter energy trading losses,[1] 2020 non-GAAP net income was $247 million, or $2.75 per diluted share. This compares with GAAP net income of $214 million, or $2.39 per diluted share, for the year ended Dec. 31, 2019. Energy deliveries increased despite the pandemic, with particularly strong growth in high-tech and digital industrial customer demand. Operating and administrative expenses decreased 6% year over year, driven by efficiencies implemented throughout PGE's operations.

As we look ahead, our long-term growth prospects remain strong. We continue to reduce costs throughout our organization and invest in our system. We are on track to achieve 4 to 6% long-term EPS growth target and 5 to 7% long-term dividend growth target. Full-year earnings guidance for 2021 is $2.55 to $2.70 per diluted share.

Our results in 2020 are a testament to the strength of our operations, the resilience of our team, and our unwavering commitment to our customers and role as an essential service provider serving Oregonians with the clean energy they want.

## LOOKING FORWARD

The success of our company and the value we deliver to shareholders are directly connected to the value we deliver to customers, employees and the communities we serve. We know that, together, we each have a role to play to achieve our shared climate goals and create a clean energy economy that benefits all.

I would like to thank Board Chair Jack Davis and members of the board, whose collective counsel was invaluable in navigating 2020. I would also like to thank John Ballantine and Chuck Shivery, who will be concluding their time on the board at the 2021 annual meeting, for their service and welcome Michael Lewis and Jim Torgerson. Finally, I would like to acknowledge that 2020 marked the retirement of Jim Lobdell, who served PGE for 36 years, and the beginning of Jim Ajello's leadership as PGE's Chief Financial Officer in January 2021.

In closing, I would like to spotlight the more than 4,000 employees and contractors who keep the lights on for customers — managing through the pandemic, social unrest, energy trading losses, wildfires and other challenges of 2020. Their commitment to our customers and the communities we serve is inspiring, and I am proud to work alongside them every day.

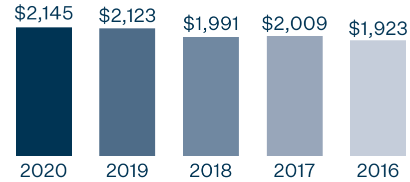
# Financial Highlights

## ABOUT PORTLAND GENERAL ELECTRIC

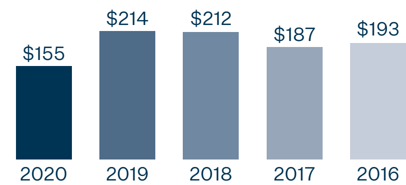
Portland General Electric Company, headquartered in Portland, Oregon, is a fully integrated electric utility serving approximately 900,000 retail customers in Oregon. PGE common stock is traded on the New York Stock Exchange under the ticker symbol POR.

| *Dollars in millions, except per-share amounts* | 2020 | 2019 | 2018 | 2017 | 2016 |
|---|---|---|---|---|---|
| Total operating revenue | $2,145 | $2,123 | $1,991 | $2,009 | $1,923 |
| Operating income | $269 | $353 | $346 | $380 | $340 |
| Net income | $155 | $214 | $212 | $187[(1)] | $193 |
| Earnings per share, diluted | $1.72 | $2.39 | $2.37 | $2.10[(1)] | $2.16 |
| Return on average equity | 6.0% | 8.4% | 8.6% | 7.9% | 8.4% |
| Total assets | $9,069 | $8,394 | $8,110 | $7,838 | $7,527 |
| Dividends declared per common share | $1.59 | $1.52 | $1.43 | $1.34 | $1.26 |
| Weighted-average shares outstanding (in thousands), diluted | 89,645 | 89,559 | 89,347 | 89,176 | 89,054 |
| Average number of customers throughout the year | 902,000 | 890,000 | 882,000 | 870,000 | 859,000 |
| Common equity ratio[(2)] | 45.0% | 49.9% | 50.3% | 49.9% | 49.9% |
| Senior secured debt ratings (S&P/Moody's) | A/A1 | A/A1 | A/A1 | A-/A1 | A-/A1 |
| Commercial paper ratings (S&P/Moody's) | A-2/P-2 | A-2/P-2 | A-2/P-2 | A-2/P-2 | A-2/P-2 |
| Employees | 2,870 | 2,949 | 2,967 | 2,906 | 2,752 |

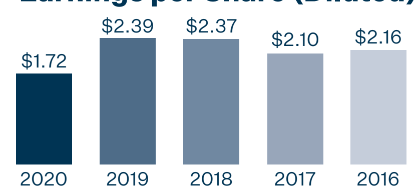
### Total Operating Revenue



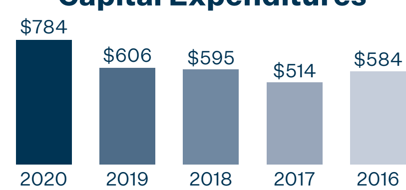

### Net Income



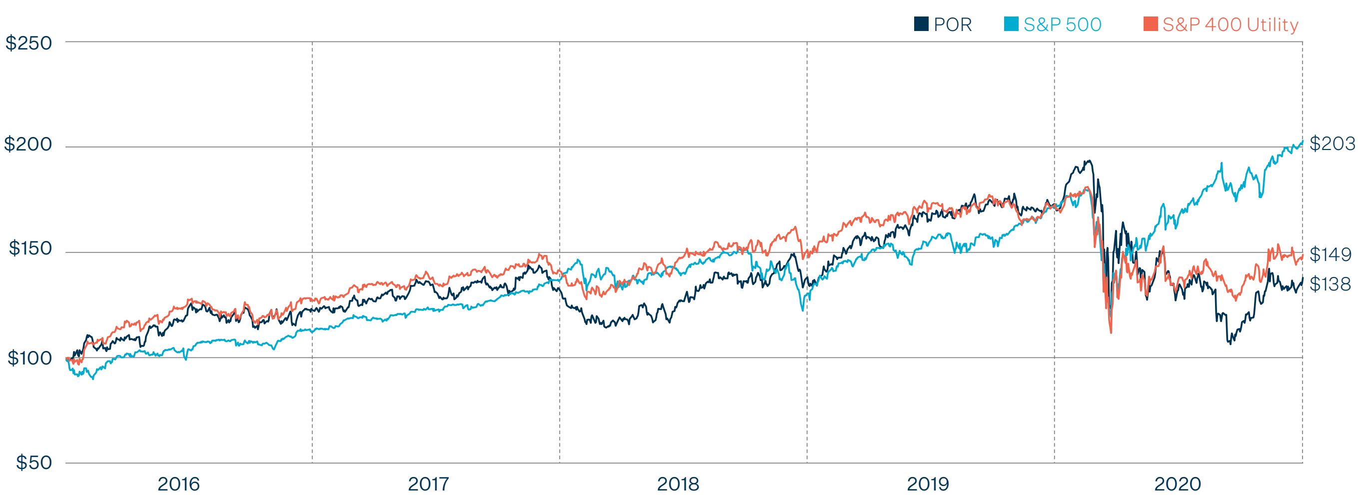

### Earnings per Share (Diluted)




### Capital Expenditures




## STOCK PERFORMANCE[(3)]




(1) Non-GAAP net income and diluted earnings per share excluding the effects of the federal Tax Cuts and Jobs Act was $204 million and $2.29, respectively.

(2) Excludes lease obligations.

(3) The chart above assumes a $100 investment in Portland General Electric's common stock and each index on Dec. 31, 2015, and that all dividends were reinvested.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

# FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the fiscal year ended December 31, 2020**

**OR**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the Transition period from ______ to ______**

**Commission File Number 001-05532-99**

# PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Oregon** | **93-0256820** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

**121 S.W. Salmon Street**
**Portland, Oregon 97204**
**(503) 464-8000**
(Address of principal executive offices, including zip code, and Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

| (Title of class) | (Trading symbol) | (Name of exchange on which registered) |
|---|---|---|
| Common Stock, no par value | POR | New York Stock Exchange |
| 9.31% Medium-Term Notes due 2021 | POR 21 | New York Stock Exchange |

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

| | | | |
|---|---|---|---|
| Large accelerated filer | ☒ | Accelerated filer | ☐ |
| Non-accelerated filer | ☐ | Smaller reporting company | ☐ |
| | | Emerging growth company | ☐ |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of June 30, 2020, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $3,725,882,304. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 10, 2021, there were 89,539,034 shares of common stock outstanding.

**Documents Incorporated by Reference**

| | |
|---|---|
| Part III, Items 10 - 14 | Portions of Portland General Electric Company's definitive proxy statement to be filed pursuant to Regulation 14A for the Annual Meeting of Shareholders to be held on April 28, 2021. |

**PORTLAND GENERAL ELECTRIC COMPANY**
**FORM 10-K**
**FOR THE YEAR ENDED DECEMBER 31, 2020**

## TABLE OF CONTENTS

## DEFINITIONS

The abbreviations or acronyms defined below are used throughout this Form 10-K:

| Abbreviation or Acronym | Definition |
|---|---|
| AFDC | Allowance for funds used during construction |
| ARO | Asset retirement obligation |
| AUT | Annual Power Cost Update Tariff |
| Beaver | Beaver natural gas-fired generating plant |
| Biglow Canyon | Biglow Canyon Wind Farm |
| Boardman | Boardman coal-fired generating plant |
| BPA | Bonneville Power Administration |
| Carty | Carty natural gas-fired generating plant |
| Colstrip | Colstrip Units 3 and 4 coal-fired generating plant |
| Coyote Springs | Coyote Springs Unit 1 natural gas-fired generating plant |
| Dth | Decatherm = 10 therms = 1,000 cubic feet of natural gas |
| EIM | Energy Imbalance Market |
| EPA | United States Environmental Protection Agency |
| ESS | Electricity Service Supplier |
| FERC | Federal Energy Regulatory Commission |
| FMB | First Mortgage Bond |
| FPA | Federal Power Act |
| GRC | General Rate Case for a specified test year |
| IRP | Integrated Resource Plan |
| ISFSI | Independent Spent Fuel Storage Installation |
| kV | Kilovolt = one thousand volts of electricity |
| Moody’s | Moody’s Investors Service |
| MW | Megawatts |
| MWa | Average megawatts |
| MWh | Megawatt hours |
| NRC | Nuclear Regulatory Commission |
| NVPC | Net Variable Power Costs |
| OATT | Open Access Transmission Tariff |
| OPUC | Public Utility Commission of Oregon |
| PCAM | Power Cost Adjustment Mechanism |
| PTC | Federal production tax credit |
| PW1 | Port Westward Unit 1 natural gas-fired generating plant |
| PW2 | Port Westward Unit 2 natural gas-fired flexible capacity generating plant |
| QF | PURPA qualifying facility |
| RAC | Renewable Adjustment Clause |
| RPS | Renewable Portfolio Standard |
| S&P | S&P Global Ratings |
| SEC | United States Securities and Exchange Commission |
| Trojan | Trojan nuclear power plant |
| Tucannon River | Tucannon River Wind Farm |
| USDOE | United States Department of Energy |

# PART I

## ITEM 1. BUSINESS.

## General

Portland General Electric Company (PGE or the Company), a vertically-integrated electric utility with corporate headquarters located in Portland, Oregon, is engaged in the generation, wholesale purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company operates as a cost-based, regulated electric utility with revenue requirements and customer prices determined based on the forecasted cost to serve retail customers and a reasonable rate of return as determined by the Public Utility Commission of Oregon (OPUC). PGE meets its retail load requirement with both Company-owned generation and power purchased in the wholesale market. The Company participates in the wholesale market through the purchase and sale of electricity and natural gas in an effort to obtain reasonably-priced power to serve its retail customers. PGE, incorporated in 1930, is publicly-owned, with its common stock listed on the New York Stock Exchange (NYSE). The Company operates as a single business segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis.

PGE's state-approved service area allocation of four thousand square miles is located entirely within Oregon and includes 51 incorporated cities. During 2020, the Company added 13 thousand customers, and as of December 31, 2020, served a total of 908 thousand retail customers.

### *Available Information*

PGE's periodic and current reports, and amendments to those reports, are available and may be accessed free of charge through the Investors section of the Company's website at PortlandGeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). It is not intended that PGE's website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K.

## Regulation

Federal and state of Oregon (State) regulation each have a significant impact on the operations of PGE. In addition to the agencies and activities discussed below, the Company is subject to regulation by certain environmental agencies, as described in the Environmental Matters section in this Item 1.

### *Federal Regulation*

Several federal agencies, including the Federal Energy Regulatory Commission (FERC), the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Nuclear Regulatory Commission (NRC), have regulatory authority over certain of PGE's operations and activities, as described in the discussion that follows.

PGE is a "licensee," a "public utility," and a "user, owner, and operator of the bulk power system," as defined in the Federal Power Act (FPA). As such, the Company is subject to regulation by the FERC in matters related to wholesale energy activities, transmission services, reliability and cybersecurity standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters.

*Wholesale Energy*—PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales in all markets in which it sells electricity except in its own Balancing Authority Area (BAA). The BAA is the area in which PGE is responsible for balancing customer demand with electricity supply, in real time, and the tariff exception within PGE's BAA does not have a material impact on the Company.

*Transmission*—PGE offers wholesale electricity transmission service pursuant to its Open Access Transmission Tariff (OATT), which contains rates, terms, and conditions of service, as filed with, and approved by, the FERC.

*Reliability and Cybersecurity Standards*—The FERC has adopted mandatory reliability standards for owners, users, and operators of the bulk power system. Such standards, which are applicable to PGE, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which have responsibility for compliance and enforcement of these standards, and are intended to help protect critical cyber assets used to support reliable operations.

*Natural Gas Pipelines*—The FERC has authority in matters related to the construction, operation, extension, enlargement, safety, and abandonment of jurisdictional interstate natural gas pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE is subject to such authority as the Company has a 79.5% ownership interest in the Kelso-Beaver (KB) Pipeline, a 17-mile interstate pipeline that provides natural gas to Port Westward Unit 1 (PW1), Port Westward Unit 2 (PW2), and Beaver, the Company's natural gas-fired generating plants located near Clatskanie, Oregon, and to the North Mist storage facility. As the operator of record of the KB Pipeline, PGE is subject to the requirements and regulations enacted under the Pipeline Safety Laws administered by the PHMSA, which include safety standards, operator qualification standards, and public awareness requirements.

*Hydroelectric Licensing*—As required under the FPA, PGE holds FERC licenses for all Company-owned hydroelectric generating plants. The FERC license process includes an extensive public review process that involves the consideration of numerous natural resource issues and environmental conditions. For additional information, see the Environmental Matters section in this Item 1. and the Generating Facilities section in Item 2.—"Properties."

*Accounting Policies and Practices*—PGE prepares periodic and current reports in accordance with accounting principles generally accepted in the United States of America (GAAP). In addition, the Company prepares, pursuant to applicable provisions of the FPA, financial statements in accordance with the accounting requirements of the FERC, as set forth in its applicable Uniform System of Accounts and published accounting releases. Such financial statements are included in annual and quarterly reports filed with the FERC.

*Short-term Debt*—Pursuant to applicable provisions of the FPA and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. For additional information on the Company's Short-term Debt, see *Short-term Debt* in the Debt and Equity section of Liquidity and Capital Resources in Item 7. —"Management's Discussion and Analysis of Financial Condition and Results of Operations."

*Spent Fuel Storage*—The NRC regulates the licensing and decommissioning of nuclear power plants, including PGE's decommissioned Trojan nuclear power plant (Trojan), which was closed in 1993. For additional information on spent nuclear fuel storage activities, see Note 8, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data" and *"Hazardous Material"* in the Environmental Matters section of this Item 1.

### *State of Oregon Regulation*

PGE is subject to the jurisdiction of the OPUC, which reviews and approves the Company's retail prices and reviews the Company's generation and transmission resource acquisition plans, pursuant to a biennial integrated resource planning process. The OPUC regulates the issuance of securities, prescribes accounting policies and practices, regulates the sale of utility assets, reviews transactions with affiliated companies, and has jurisdiction over the acquisition of, or exertion of substantial influence over, public utilities.

Retail customer prices are determined through formal proceedings that generally include testimony by participating parties, discovery, public hearings, and the issuance of a final order. Participants in such proceedings may include PGE, OPUC staff, and intervenors representing PGE customer groups, as well as other interested parties. The following are the more significant regulatory mechanisms and proceedings under which customer prices are determined:

- *General Rate Cases*. PGE periodically evaluates the need to change its retail electric price structure as part of a comprehensive general rate case process that reflects revenue requirements based on a forecasted test year. The OPUC authorizes the Company's debt-to-equity capital structure, return on equity, overall rate of return, and customer prices.
- *Annual Power Cost Updates*. The OPUC has approved an Annual Power Cost Update Tariff (AUT) by which PGE can adjust retail customer prices annually to reflect forecasted changes in the Company's net variable power costs (NVPC). NVPC consists of the cost of power purchased and fuel used to generate electricity, as well as the cost of settled electric and natural gas financial contracts (all classified as Purchased power and fuel expense in the Company's consolidated statements of income) and is net of wholesale revenues, which are classified in the consolidated statements of income as Revenues, net. The OPUC has also authorized a Power Cost Adjustment Mechanism (PCAM), under which PGE may share with customers a portion of actual cost variances associated with NVPC.
- *Renewable Energy.* The State maintains a Renewable Portfolio Standard (RPS) that requires PGE to serve a portion of its retail load with renewable resources. In conjunction with the RPS, the State established a Renewable Adjustment Clause (RAC) mechanism that allows for the recovery in retail customer prices, outside of a general rate case, of prudently incurred costs to comply with the RPS. The State also passed a law referred to as the Oregon Clean Electricity and Coal Transition Plan (SB 1547), which, among its provisions, increased the RPS percentages in certain future years. For further information on SB 1547, see "*Carbon Legislation and Administrative Actions"* in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

*Retail Customer Choice Program*—Under cost of service pricing, residential and small commercial customers may select portfolio options from PGE that include time-of-use and renewable resource pricing.

Pricing options other than cost of service are available to certain commercial and industrial customers for a one-year period, including daily market index-based pricing under which the Company provides the electricity, and Direct Access, whereby customers purchase electricity directly from an Electricity Service Supplier (ESS).

PGE receives revenue from Direct Access customers only for the transmission and delivery of the volume of electricity delivered, along with fixed transition adjustments intended to mitigate the shifting of excess charges to the Company's cost of service customers. Certain large commercial and industrial customers may elect a fixed three-year or a minimum five-year term, to be served either by an ESS, or by the Company under the daily market index-based price option. Participation in the fixed three-year and minimum five-year opt-out programs for existing and planned load is capped at 300 average megawatts (MWa) in aggregate.

In 2018, the OPUC created and approved rules for a New Large Load Direct Access (NLDA) program, which is capped at 119 MWa, for unplanned, large, new loads and large load growth at existing sites. In January 2020, the OPUC issued an order that required PGE to begin offering enrollment in the NLDA program to eligible customers in early February 2020.

For further information regarding Direct Access deliveries, see *"Customers and Demand"* in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

### *Regulatory Accounting*

PGE prepares financial statements in accordance with GAAP and, as a regulated public utility, the effects of rate regulation are reflected in its financial statements. GAAP provides for the deferral, as regulatory assets, of certain actual or estimated costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain actual or anticipated credits that would otherwise be recognized as revenue or reduce expense can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence.

The Company periodically assesses the applicability of regulatory accounting to its business, considering both the current and anticipated future regulatory environment and related accounting guidance. For additional information, see *"Regulatory Assets and Liabilities"* in Note 2, Summary of Significant Accounting Policies, and Note 7, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

## Customers and Revenues

PGE generates revenue primarily through the sale and delivery of electricity to retail customers located exclusively in Oregon. In addition, the Company distributes power to commercial and industrial customers that choose to purchase their energy from an ESS. Although the Company includes such Direct Access customers in its customer counts and energy delivered to such customers in its total retail energy deliveries, retail revenues include only delivery charges and applicable transition adjustments for these Direct Access customers. The Company conducts retail electric operations within its service territory and competes with: i) the local natural gas distribution company for the energy needs of residential and commercial space heating, water heating, and appliances; and ii) ESSs. Energy efficiency, conservation measures and distributed solar generation also have an increasing influence on customer demand.

### *Retail Revenues*

Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 8% of PGE's total retail revenues or 12% of total retail deliveries.

PGE's Retail revenues, retail energy deliveries, and average number of retail customers consist of the following:

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2020 | | 2019 | | 2018 | |
| **Retail revenues [1] (dollars in millions):** | | | | | | |
| Residential | $ 1,030 | 53 % | $ 981 | 52 % | $ 948 | 53 % |
| Commercial | 634 | 33 | 654 | 35 | 665 | 37 |
| Industrial | 246 | 13 | 222 | 12 | 210 | 12 |
| Subtotal | 1,910 | 99 | 1,857 | 99 | 1,823 | 102 |
| Alternative revenue programs, net of amortization | (6) | — | 2 | — | 3 | — |
| Other accrued (deferred) revenues, net [2] | 28 | 1 | 22 | 1 | (45) | (2) |
| Total retail revenues | $ 1,932 | 100 % | $ 1,881 | 100 % | $ 1,781 | 100 % |
| **Retail energy deliveries [3] (MWh in thousands):** | | | | | | |
| Residential | 7,756 | 40 % | 7,471 | 38 % | 7,416 | 39 % |
| Commercial | 6,855 | 35 | 7,318 | 38 | 7,430 | 39 |
| Industrial | 4,932 | 25 | 4,671 | 24 | 4,376 | 22 |
| Total retail energy deliveries | 19,543 | 100 % | 19,460 | 100 % | 19,222 | 100 % |
| **Average number of retail customers:** | | | | | | |
| Residential | 791,119 | 88 % | 779,673 | 88 % | 772,389 | 88 % |
| Commercial | 110,851 | 12 | 110,084 | 12 | 109,107 | 12 |
| Industrial | 267 | — | 262 | — | 270 | — |
| Total | 902,237 | 100 % | 890,019 | 100 % | 881,766 | 100 % |

(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs.
(2) Amounts for the years ended December 31, 2020 and 2019 are primarily comprised of $24 million and $23 million of amortization, respectively, including interest, related to the $45 million deferral reflected in 2018 for the net tax benefits due to the change in corporate tax rate under the United States Tax Cuts and Jobs Act of 2017 (TCJA).
(3) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs.

The following table presents additional averages for retail customers. Certain supplemental tariff collections are excluded from revenues as they are not considered a part of the Company's base retail prices for these calculations.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| **Residential** | | | |
| Revenue per customer (in dollars): | $ 1,226 | $ 1,177 | $ 1,153 |
| Usage per customer (in kilowatt hours): | 9,804 | 9,582 | 9,601 |
| Revenue per kilowatt hour (in cents): | 12.50 ¢ | 12.28 ¢ | 12.01 ¢ |
| **Commercial** | | | |
| Revenue per customer (in dollars): | $ 5,684 | $ 5,901 | $ 6,051 |
| Usage per customer (in kilowatt hours): | 61,837 | 66,481 | 68,096 |
| Revenue per kilowatt hour (in cents): | 9.19 ¢ | 8.88 ¢ | 8.89 ¢ |
| **Industrial** | | | |
| Revenue per customer (in dollars): | $ 921,540 | $ 847,079 | $ 776,245 |
| Usage per customer (in kilowatt hours): | 18,472,161 | 17,827,115 | 16,207,263 |
| Revenue per kilowatt hour (in cents): | 4.99 ¢ | 4.75 ¢ | 4.79 ¢ |

For additional information, see the Results of Operations section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

In addition to standard cost of service pricing, the Company offers different pricing options including a daily market price option, various time-of-use options, and several renewable energy options, which are offered to residential and small commercial customers. For additional information on customer options, see "*Retail Customer Choice Program*" within the Regulation section of this Item 1.

*Residential* customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), mobile homes, and small farms. Residential demand is sensitive to the effects of weather, with demand historically highest during the winter heating season. Increased use of air conditioning in PGE's service territory has caused the summer peaks to increase in recent years, while the historical winter peak has not increased in over 20 years. In the past few years, summer peaks have exceeded winter peaks and long-term load forecasts expect that trend to continue. Economic conditions can also affect residential demand as job growth and population growth in PGE's service territory have led to increased customer growth rates. Residential demand is also impacted by energy efficiency measures; however, the Company's decoupling mechanism is intended to mitigate the financial effects of such measures.

*Commercial* customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. This customer class includes most businesses, small industrial companies, and public street and highway lighting accounts. The Company's commercial customer demand is somewhat less susceptible to weather conditions than residential customer demand. Economic conditions and fluctuations in total employment in the region can also lead to changes in energy demand from commercial customers. Energy efficiency measures also impact commercial demand, although the Company's decoupling mechanism partially mitigates the financial effects of such measures.

*Industrial* customers consist of non-residential customers who accept delivery at higher voltages than commercial customers, with pricing based on the amount of electricity delivered under the applicable tariff. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class.

***Wholesale Revenues***

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity, largely through bi-lateral agreements, within the region to serve retail demand, depending upon the relative price and availability of power, hydro and wind conditions, and daily and seasonal retail demand. PGE also participates in the California Independent System Operator's western Energy Imbalance Market (western EIM), which allows for load balancing with other western EIM participants in five-minute intervals. Wholesale revenues represented 8% of total revenues in 2020, 2019, and 2018.

***Other Operating Revenues***

Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Company's generating facilities, as well as revenues from transmission services, excess transmission capacity resales, pole attachment rentals, and other electric services provided to customers. Other operating revenues represented 2% of total revenues in 2020, and 3% in 2019 and 2018.

***Seasonality***

Demand for electricity by PGE's residential and, to a lesser extent, commercial customers, is affected by seasonal weather conditions. The Company uses heating and cooling degree-days to determine the effect of weather on the demand for electricity. Heating and cooling degree-days, determined by taking the difference between the average daily temperature and a baseline of 65 degrees, provide cumulative variances over a period of time, to indicate the extent to which customers are likely to have used electricity for heating or cooling. The higher the number of degree-days, the greater the expected demand for electricity.

The following table presents the heating and cooling degree-days for the most recent three-year period, along with 15-year averages for the most recent year provided by the National Weather Service, as measured at Portland International Airport:

| | Heating Degree-Days | Cooling Degree-Days |
|---|---|---|
| **2020** | 3,836 | 600 |
| **2019** | 4,165 | 564 |
| **2018** | 3,702 | 692 |
| **15-year average** | 4,145 | 538 |

PGE's all-time high net system load peak of 4,073 megawatts (MW) occurred in December 1998. The Company's all-time summer peak of 3,976 MW occurred in August 2017. The following table presents PGE's average winter (defined as January, February, and December) and summer (defined as June through September) loads for the periods presented, along with the corresponding peak load (in MWs) and month in which such peak occurred. As the table below illustrates, although the average winter loads continue to run higher than average summer loads, the Company continues to experience its highest annual peak loads during the summer months:

| | Winter Loads | | | Summer Loads | | |
|---|---|---|---|---|---|---|
| | Average | Peak | Month | Average | Peak | Month |
| **2020** | 2,566 | 3,367 | December | 2,289 | 3,771 | July |
| **2019** | 2,609 | 3,422 | February | 2,263 | 3,765 | June |
| **2018** | 2,519 | 3,399 | February | 2,301 | 3,816 | August |

The Company tracks and evaluates both load growth and peak load requirements for purposes of long-term load forecasting, integrated resource planning, and preparing general rate case (GRC) assumptions. Behavior patterns, conservation, energy efficiency initiatives and measures, weather effects, economic conditions, and demographic changes all play a role in determining expected future customer demand and the resulting resources the Company will need to adequately meet those loads and maintain adequate capacity reserves.

## Power Supply

PGE utilizes its generating resources, as well as wholesale power purchases from third parties to meet the needs of its retail customers. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources and the price and availability of wholesale power and natural gas. As part of its power supply operations, the Company enters into short- and long-term power and fuel purchase and sale agreements. PGE executes economic dispatch decisions concerning its own generation and participates in the wholesale market in an effort to obtain reasonably-priced power for its retail customers, manage risk, and administer its long-term wholesale contracts. The Company also encourages energy efficiency measures to help meet its energy requirements and promotes the use of various demand side management products to reduce load during peak time usage.

PGE's resource and contracted capacity (in MW) was as follows:

| | As of December 31, | | | |
|---|---|---|---|---|
| | 2020 | | 2019 | |
| | Capacity | % | Capacity | % |
| Generation: | | | | |
| Thermal [(1)]: | | | | |
| Natural gas | 1,831 | 34 % | 1,830 | 35 % |
| Coal | 296 | 6 | 814 | 15 |
| Total thermal | 2,127 | 40 | 2,644 | 50 |
| Wind [(2)] | 817 | 16 | 717 | 14 |
| Hydro [(3)] | 495 | 9 | 495 | 9 |
| Total generation | 3,439 | 65 | 3,856 | 73 |
| Purchased power: | | | | |
| Long-term contracts: | | | | |
| Hydro [(3)] | 512 | 10 | 462 | 9 |
| PURPA qualifying facilities [(4)] | 279 | 5 | 133 | 3 |
| Dispatchable standby generation | 123 | 2 | 125 | 2 |
| Capacity | 100 | 2 | 100 | 2 |
| Wind [(2)] | 300 | 6 | 100 | 2 |
| Solar | 7 | — | 7 | — |
| Biomass | 10 | — | 10 | — |
| Total long-term contracts | 1,331 | 25 | 937 | 18 |
| Short-term contracts | 538 | 10 | 471 | 9 |
| Total purchased power | 1,869 | 35 | 1,408 | 27 |
| Total resource capacity | 5,308 | 100 % | 5,264 | 100 % |

(1) Capacity represents the MW the plants are capable of generating under normal operating conditions, which is affected by ambient temperatures, net of electricity used in the operation of the plant. PGE's Boardman coal-fired generating plant (Boardman) ceased coal-fired operations during the fourth quarter of 2020.
(2) Capacity represents nameplate and differs from expected energy to be generated, which is expected to have a capacity factor range from 30 to 40%, dependent upon wind conditions.
(3) Capacity represents net capacity and differs from expected energy to be generated, which is expected to have a capacity factor range from 40 to 50%, dependent upon river flows.
(4) Capacity represents contracted capacity under the Public Utility Regulatory Policies Act of 1978 (PURPA).

For information regarding actual generating output and purchases for the years ended December 31, 2020 and 2019, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

***Generation***

PGE's generating resources consist of six thermal plants (natural gas- and coal-fired), three wind farms, and seven hydroelectric facilities. The portion of PGE's retail load requirements generated by its plants varies from year to year and is determined by various factors, including planned and unplanned outages, availability and price of coal and natural gas, precipitation and snow-pack levels, the market price of electricity, and wind variability. For a complete listing of these facilities, see "*Generating Facilities*" in Item 2.—"Properties."

**Thermal** The Company has five natural gas-fired generating facilities: PW1, PW2, Beaver, Coyote Springs Unit 1 (Coyote Springs), and Carty Generating Station (Carty).

The Company operated, and continues to have a 90% ownership interest in, Boardman, which ceased coal-fired operations during the fourth quarter of 2020. The Company has begun the initial steps toward decommissioning the facility. The Company also has a 20% ownership interest in the Colstrip Units 3 and 4 coal-fired generating plant (Colstrip), which is operated by a third party. Pursuant to SB 1547, PGE's portion of Colstrip is scheduled to be fully depreciated by 2030, with the potential to utilize the output of the facility, in Oregon, until 2035. For additional information on SB 1547, see *"Carbon Legislation and Administrative Actions"* in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

**Wind** PGE owns and operates two wind farms, Biglow Canyon Wind Farm (Biglow Canyon) and Tucannon River Wind Farm (Tucannon River). Biglow Canyon, located in Sherman County, Oregon, is PGE's largest renewable energy resource consisting of 217 turbines with a total nameplate capacity of 450 MW. Tucannon River, located in southeastern Washington, consists of 116 turbines with a total nameplate capacity of 267 MW. During 2020, the wind component of the Wheatridge Renewable Energy Facility (Wheatridge), located in Morrow County, Oregon, was placed into service. Although PGE does not operate Wheatridge, it now owns 40 turbines with a total nameplate capacity of 100 MW and purchases the output of the remaining turbines, with a capacity of 200 MWs through power purchase agreements. For additional information on Wheatridge, see *"The Resource Planning Process"* in the Overview section in Item 7. —"Management's Discussion and Analysis of Financial Condition and Results of Operations."

**Hydro** The Company's FERC-licensed hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River.

PGE has a 66.67% ownership interest in the 455 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The CTWS has an option to purchase an additional undivided 16.66% interest in Pelton/Round Butte at their discretion on December 31, 2021. CTWS has a second option in 2036 to purchase an undivided 0.02% interest in Pelton/Round Butte. If both options are exercised, CTWS's ownership percentage would exceed 50%.

*Fuel Supply*—PGE contracts for natural gas and coal supplies required to fuel the Company's thermal generating plants, with certain plants also able to operate on fuel oil, if needed. In addition, the Company uses forward, future, swap, and option contracts to manage its exposure to volatility in natural gas prices.

**Natural Gas** Physical supplies of natural gas are generally purchased up to twelve months in advance of delivery and based on anticipated operation of the plants. PGE manages the price risk of natural gas supply through the use of financial contracts up to 60 months in advance of expected need of energy.

PGE owns 79.5%, and is the operator of record, of the KB Pipeline, which directly connects PW1, PW2, and Beaver to the Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports natural gas on the KB Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company. PGE has access to 103,305 Dth per day of firm natural gas transportation capacity on the Northwest Pipeline to serve the three plants.

PGE has access to 4.1 billion cubic feet of natural gas storage in Mist, Oregon from which it can draw when economic factors favor its use or in the event that natural gas supplies are interrupted.

The storage facility is owned and operated by NW Natural, and may be utilized to provide fuel to PW1, PW2, and Beaver.

To serve Coyote Springs and Carty, PGE has access to 120,000 Dth per day of firm natural gas transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada.

**Coal** The Colstrip co-owners obtain coal to fuel the plant via conveyor belt from a mine that lies adjacent to the facility and is the sole source of coal supply for the plant. The coal supply contract with the owner of the mine is scheduled to expire at the end of 2025. The terms of contracts and the quality of coal are expected to be in alignment with required emissions limits.

***Purchased Power***

PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost basis.

PGE's medium-term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE mitigates a portion of the potential future volatility in the average cost of purchased power and fuel.

The Company's major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts):

*Hydro*—During 2020, the Company had the following agreements:

- *Public Utility Districts*—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington for a portion of the output of two hydroelectric projects on the mid-Columbia River. Although the projects currently provide a total of 313 MW of capacity, actual energy received is dependent upon river flows and capacity amounts may decline over time:
    - one contract, with Grant County PUD, representing 165 MW of capacity that expires in 2052;
    - one contract, with Douglas County PUD, representing 148 MW of capacity that expires in 2028; and
    - another contract with Douglas County PUD that is a five-year agreement starting January 1, 2021 to supply the Company with additional capacity between 100 and 160 MW, which is not reflected in the table above.
- *CTWS*—PGE has a long-term agreement under which the Company purchases, at index prices, CTWS' interest in the output of the Pelton/Round Butte hydroelectric project. Although the agreement provides approximately 162 MW of net capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055. In 2014, PGE entered into an agreement with CTWS under which CTWS has agreed to sell, on modified payment terms, its share of the energy generated from the Pelton/Round Butte hydroelectric project exclusively to the Company through 2024.
- *Other*—PGE has two additional contracts that provide for the purchase of power generated from hydroelectric projects in Oregon with capacity of 37 MW in total. One contract for 36 MW expires in 2032 while the second has no expiration date.

*PURPA qualifying facilities*—PGE is required to purchase power from PURPA qualifying facilities (QFs), as mandated by federal law. QFs are generating facilities that fall within the following two categories: i) qualifying generation facilities with a capacity of 80 MW or less and whose primary energy source is renewable (hydro, wind, solar, biomass, waste, or geothermal); or ii) qualifying cogeneration facilities that sequentially produce electricity and another form of useful thermal energy (e.g., heat, steam) in a way that is more efficient than the separate production of each form of energy. As of December 31, 2020, PGE had contracts with 60 on-line PURPA qualifying facilities, providing a total of 279 MW of capacity. As of December 31, 2020, PGE has 36 contracts with PURPA QFs representing 164 MW of capacity that are not yet operational, of which 34 of the QF power purchase agreements (PPAs) are in default because the QF has failed to complete construction and become operational by the date required by the PPA. The PPAs provide that the QF has one year to cure its default. If the QF has failed to cure, PGE is permitted to immediately terminate the QF PPA upon expiration of the cure period. The term of a QF PPA generally ranges from 15 to 23 years, measured from the date of execution.

The expense and volume of purchases from QFs for the years ended December 31, 2020 and 2019 were as follows:

| | 2020 | 2019 |
|---|---|---|
| PURPA contract expense (in millions) | $ 43 | $ 6 |
| MWh purchased under PURPA contracts (in thousands) | 498 | 152 |
| Average cost per MWh from PURPA contracts | $ 85.31 | $ 38.69 |

Expenses incurred related to PURPA contracts are included in PGE's AUT.

*Dispatchable Standby Generation (DSG)*—PGE has a DSG program under which the Company can start, operate, and monitor customer-owned diesel-fueled standby generators when needed to provide NERC-required operating reserves. As of December 31, 2020, there were 53 customer-owned sites with a total DSG capacity of 123 MW. PGE continues to pursue expansion of the program with the goal of having an additional 3 MW of customer-owned DSG projects online by the end of 2022.

*Capacity*—PGE's capacity contracts are primarily comprised of the following agreements to help meet peak loads:

- Seasonal peaking capacity up to 100 MW during the summer and winter peak periods obtained from a natural gas-fired resource, which expires in 2024; and
- Starting in January 2021, an additional 200 MW of annual capacity will be added, with a five-year term, primarily obtained from hydroelectric resources.

*Wind*—PGE has three contracts representing 300 MW of capacity to purchase power generated from renewable wind resources that extend to 2028, 2035, and 2050. The expected energy from these wind resources will vary from the nameplate capacity due to varying wind conditions.

*Solar*—PGE has three contracts representing 7 MW of capacity to purchase power generated from photovoltaic solar projects that extend to 2036 and 2037. The expected energy from these solar resources will vary from the nameplate capacity due to varying solar conditions.

*Biomass*—PGE has one contract to purchase biomass energy that is set to expire in 2021.

*Short-term contracts*—These contracts are for delivery periods of one month up to one year in length. They are entered into with various counterparties to provide additional firm energy to help meet the Company's load requirements.

PGE also utilizes spot purchases of power in the open market to secure the energy required to serve its retail customers. Such purchases are made under contracts that range in duration from 15 minutes to less than one month.

As of 2017, PGE became a market participant in the western EIM, which allows certain of the Company's generating plants to receive automated dispatch signals from the California Independent System Operator (CAISO) for load balancing with other western EIM participants in five-minute intervals.

For additional information regarding PGE's power purchase contracts, see Note 16, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

***Future Energy Resource Strategy***

PGE's Integrated Resource Plan (IRP) outlines the Company's plan to meet future customer demand and describes PGE's future energy supply strategy. For a detailed discussion of the IRPs, see *"The Resource Planning Process"* within the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

## Transmission and Distribution

Transmission systems deliver energy from generating facilities to distribution systems for final delivery to customers. PGE schedules energy deliveries over its transmission system in accordance with FERC requirements and operates one balancing authority area (an electric system bounded by interchange metering) in its service territory. In 2020, PGE delivered approximately 25 million megawatt hours (MWh) in its balancing authority area through 1,269 circuit miles of transmission lines operating at or above 115 kilovolts (kV).

PGE's transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 11 western states, two Canadian provinces and parts of Mexico, and is subject to the reliability rules of the WECC and the NERC. PGE relies on transmission contracts with Bonneville Power Administration (BPA) to transmit a significant amount of the Company's generation to serve its distribution system. PGE's transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers' energy requirements. PGE's generation is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency.

The Company's wholesale transmission activities are regulated by the FERC and are offered on a non-discriminatory basis, with all potential customers provided equal access to PGE's transmission system through PGE's OATT. In accordance with its OATT, PGE offers several transmission services to wholesale customers, including:

- Network integration transmission service, a service that integrates generating resources to serve retail loads;
- Short- and long-term firm point-to-point transmission service, a service with fixed delivery and receipt points; and
- Non-firm point-to-point service, an "as available" service with fixed delivery and receipt points.

For additional information regarding the Company's transmission and distribution facilities, see "*Transmission and Distribution*" in Item 2.—"Properties."

## Environmental Matters

PGE's operations are subject to a wide range of environmental protection laws and regulations, which pertain to air and water quality, endangered species and wildlife protection, and hazardous material. Various state and federal agencies regulate environmental matters that relate to the siting, construction, and operation of generation, transmission, and substation facilities and the handling, accumulation, clean-up, and disposal of toxic and hazardous substances. In addition, certain of the Company's hydroelectric projects and transmission facilities are located on property under the jurisdiction of federal and state agencies, and/or tribal entities that have authority in environmental protection matters. The following discussion provides further information on certain regulations that affect the Company's operations and facilities.

***Air Quality***

*Clean Air Act*—PGE's operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA), which addresses particulate matter, hazardous air pollutants, and greenhouse gas (GHG) emissions, among other things. Oregon and Montana, the states in which PGE's thermal facilities are located, also implement and administer certain portions of the CAA and have set standards that are at least as stringent as federal standards. PGE manages its air emissions at its thermal generating plants by the use of low sulfur fuel, emissions and combustion controls and monitoring, and sulfur dioxide allowances awarded under the CAA.

*Climate Change*—In 2015, the United States Environmental Protection Agency (EPA) released the Clean Power Plan (CPP), under which each state would have to reduce carbon dioxide emissions from its power sector on a state-wide basis. In 2016, the United States Supreme Court halted implementation and enforcement of the CPP.

In 2018, the EPA proposed the Affordable Clean Energy (ACE) rule, to repeal and replace the CPP and, in 2019, finalized the ACE rule, which established guidelines for states to develop plans to address GHG emissions from existing coal-fired plants, such as Colstrip in the case of PGE. With the finalization of the ACE rule, the CPP was repealed. However, on January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE rule and remanded it, in full, back to the EPA, the impact of which casts uncertainty on the status of the CPP, as the court did not say whether it viewed its decision on the ACE rule as reinstatement of the CPP.

The EPA has now been directed to review all climate and environmental rules promulgated over the past four years, including the ACE rule. The Company will continue to monitor any challenges to the recent ACE rule decision, and how the EPA will replace the ACE rule, and potentially the CPP, for impacts on Colstrip and its existing natural gas fleet.

Any laws that would impose taxes or mandatory reductions in GHG emissions may have a material impact on PGE's operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. If incremental costs were incurred as a result of changes in the regulations regarding GHGs, the Company would seek recovery in customer prices.

PGE's carbon-emitting facilities provided 62% of the Company's net generating capacity at December 31, 2020.

For more information regarding GHGs and related environmental regulation, see "*Carbon Legislation and Administrative Actions"* in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

***Water Quality***

The federal Clean Water Act requires that any federal license or permit to conduct an activity that may result in a discharge to waters of the United States must first receive a water quality certification from the state in which the activity will occur. In Oregon, Montana, and Washington, the Departments of Environmental Quality are responsible for reviewing proposed projects under this requirement to ensure that federally approved activities will meet water quality standards and policies established by the respective state. PGE has obtained permits where required and has certificates of compliance for its hydroelectric operations under the FERC licenses. The Company is currently subject to litigation with regard to water quality conditions on the Deschutes River. For additional information on this litigation see "*Deschutes River Alliance Clean Water Act Claims"* in Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

### *Threatened and Endangered Species and Wildlife*

*Fish Protection*—The federal Endangered Species Act (ESA) has granted protection to many populations of migratory fish species in the Pacific Northwest. Long-term recovery plans for these species continue to have operational impacts on many of the region's hydroelectric projects. PGE continues to implement fish protection measures at its hydroelectric projects that were prescribed by the U.S. Fish and Wildlife Service and the National Marine Fisheries Service under their authority granted in the ESA and the FPA. Conditions required with the operating licenses are expected to result in a minor reduction in power production and continued capital spending to modify the facilities to enhance fish passage and survival.

*Avian Protection*—Various statutes, including the Migratory Bird Treaty Act and Bald and Golden Eagle Protection Act, contain provisions for civil, criminal, and administrative penalties resulting from the unauthorized take of migratory birds and eagles. Because PGE operates facilities that can pose risks to a variety of such birds, the Company developed an Avian Protection Plan to help address and reduce risks to bird species that may be affected by Company operations. PGE has implemented such a plan for its transmission, distribution, and thermal generation facilities and continues to finalize additional plans for its wind generation facilities.

### *Hazardous Material*

PGE has a comprehensive program to comply with requirements of both federal and state regulations related to the storage, handling, and disposal of hazardous materials. The handling and disposal of hazardous materials from Company facilities is subject to regulation under the federal Resource Conservation and Recovery Act. In addition, the use, disposal, and clean-up of polychlorinated biphenyls, contained in certain electrical equipment, are regulated under the federal Toxic Substances Control Act.

PGE is also subject to regulation under the Comprehensive Environmental Response Compensation and Liability Act, commonly referred to as Superfund, which provides authority to the EPA to assert joint and several liability for investigation and remediation costs for designated Superfund sites.

An investigation by the EPA that began in 1997 of a segment of the Willamette River in Oregon known as Portland Harbor, revealed significant contamination of river sediments and prompted the EPA to designate Portland Harbor as a Superfund site. The EPA has listed PGE among the more than one hundred Potentially Responsible Parties (PRPs) in this matter, as PGE historically owned or operated property near the river. For additional information regarding the EPA action on Portland Harbor, see Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

PGE is subject to regulation by the United States Department of Energy (USDOE), which, under the Nuclear Waste Policy Act of 1982, is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel from Trojan that is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-licensed interim dry storage facility that houses the fuel at the former plant site. The NRC approved the transfer of spent nuclear fuel from a spent fuel pool to the ISFSI where it is expected to remain until permanent off-site storage is available. Shipment of the spent nuclear fuel from the ISFSI to off-site storage is not expected to be completed prior to 2059. For additional information regarding this matter, see "*Trojan decommissioning activities*" in Note 8, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

## Human Capital Management

PGE's talent and culture are vital to its ability to execute its business strategy and realize continued success. Accordingly, the Company seeks to attract and retain a talented, motivated, and diverse workforce and maintain a culture that reflects PGE's core values, drive for performance, and commitment to acting with the highest levels of honesty, integrity, and compliance.

*Employees and Collective Bargaining Agreements*—PGE had 3,639 members in its workforce (769 of which are contingent workers) as of December 31, 2020, with 721 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers (IBEW). The agreements cover 660 and 61 employees and expire March 2022 and August 2022, respectively. The partnership with IBEW is key to a holistic labor relations approach.

*Competitive Pay and Benefits*—PGE is committed to ensuring pay equity among its employees and offers a wide range of market-competitive benefits, including comprehensive health and welfare benefits and a 401(k) retirement plan, designed to support the physical, mental, and financial well-being of its employees.

*Talent development* —PGE provides a variety of training and development programs for employees, as well as tuition reimbursement for job-related coursework. The Board oversees executive talent development with the assistance of the Governance Committee and the Compensation Committee in an effort to maximize the pool of internal candidates. In addition, the Compensation Committee regularly conducts more in-depth reviews of development plans for promising management talent for promotion and advancement.

*Health and safety*—PGE is committed to providing a safe and healthy place of business for employees, customers, and the public. Management has established an Executive Safety Council that has oversight of the Company's efforts to create a safe workplace. In addition, PGE provides various safety resources to its employees, such as safety manuals, trainings, and incident reporting tools that are all designed to incorporate safe practices into all daily activities and promote in all employees a sense of personal commitment, responsibility, and obligation regarding safety.

*Diversity, Equity and Inclusion* —PGE promotes an inclusive workforce through pay equity practices, racial equity training, and development opportunities for women and people of color to advance into management. Black, Indigenous, and People of Color comprise over 22% of its employees and nearly 19% of management. Nearly one third of its employees and over 31% of its management, including its CEO, are female. PGE also promotes diversity and economic development through its suppliers. The Company's supplier diversity program ensures opportunity in all competitive bid events for qualified minority-owned, women-owned, disabled veteran-owned, and emerging small business suppliers.

*COVID-19* — In response to the COVID-19 pandemic, PGE took immediate steps to protect employees by making changes to work schedules, work locations, cleaning practices, work protocols, and information services—including encouraging employees to take advantage of its comprehensive health, wellness, family, and leave programs.

## Information about Our Executive Officers

The following are PGE's current executive officers:

| Name | Age | Current Position and Previous Experience | Year Appointed Officer |
|---|---|---|---|
| James A. Ajello | 67 | Senior Vice President, Finance, Chief Financial Officer and Treasurer (January 2021 to present), Senior Advisor (November 2020 to December 2020), Executive Vice President and Chief Financial Officer at Hawaiian Electric Industries (January 2009 to April 2017 - retired), Senior Vice President, Business Development at Reliant Energy (January 2000 to January 2009), Managing Director, UBS Securities (January 1984 to August 1998). | 2021 |
| Larry N. Bekkedahl | 59 | Vice President, Grid Architecture, Integration and Systems Operations (January 2019 to present), Vice President Transmission and Distribution (August 2014 to January 2019). Senior Vice President of Transmission Services at BPA (June 2012 to August 2014), Vice President of Engineering and Technical Services at BPA (2008 to June 2012). | 2014 |
| Bradley Y. Jenkins | 57 | Vice President, Utility Operations (January 2019 to present), Vice President, Generation and Power Operations (October 2017 to January 2019), Vice President, Power Supply Generation (September 2015 to October 2017), General Manager, Diversified Plant Operations, (November 2013 to August 2015), Plant General Manager, Boardman (September 2012 to November 2013), Operations Manager, Boardman (March 2012 to September 2012). | 2015 |
| Lisa A. Kaner | 60 | Vice President, General Counsel and Corporate Compliance Officer (July 2017 to present), trial attorney and shareholder at Markowitz Herbold PC (1994 to June 2017). | 2017 |
| John T. Kochavatr | 47 | Vice President, Information Technology and Chief Information Officer (February 2018 to present). Senior Vice President and Chief Information Officer at SUEZ Water Technologies & Solutions (formerly General Electric Water and Process Technologies) (October 2017 to January 2018), Chief Information Officer and Chief Digital Officer at General Electric Water and Process Technologies (November 2012 to September 2017). | 2018 |
| John C. McFarland | 40 | Vice President, Chief Customer Officer (April 2019 to present). Director, Global Digital Experience at General Motors (February 2016 to March 2019), Chief Marketing Officer at OnStar (a subsidiary of General Motors, October 2012 to January 2016), Senior Manager of Strategy at General Motors (September 2010 to September 2012), Brand Management and Finance at Procter & Gamble (August 2002 to August 2010). | 2019 |
| Anne F. Mersereau | 58 | Vice President, Human Resources, Diversity, Equity and Inclusion (January 2016 to present), Employee Services Manager (January 2014 to January 2016), Change Management Consultant (January 2012 to January 2014), Human Resources Business Partner (July 2009 to December 2011). | 2016 |
| Maria M. Pope | 55 | President (October 2017 to present) and Chief Executive Officer (January 2018 to present), Senior Vice President, Power Supply, Operations and Resource Strategy (March 2013 to December 2017), Senior Vice President, Finance, Chief Financial Officer and Treasurer (January 2009 to February 2013). Board director (January 2006 to December 2008). Vice President and Chief Financial Officer for Mentor Graphics Corporation (July 2007 to December 2008). | 2009 |
| W. David Robertson | 53 | Vice President, Public Affairs (August 2009 to present), Director of Government Affairs (June 2004 to August 2009). | 2009 |
| Brett M. Sims | 52 | Vice President, Strategy, Regulation and Energy Supply (October 2020 to present), Senior Director of Strategy, Commercial and Regulatory Affairs (September 2017 to October 2020), Director of Origination, Structuring & Resource Strategy (May 2001 to September 2017). | 2020 |
| Kristin A. Stathis | 57 | Vice President, Operations Services (May 2019 to present), Vice President, Customer Solutions (January 2019 to May 2019), Vice President, Customer Service Operations (June 2011 to December 2018), General Manager of Revenue Operations (August 2009 to May 2011), Assistant Treasurer and Manager of Corporate Finance (October 2005 to July 2009), General Manager of Power Supply Risk Management (August 2003 to September 2005). | 2011 |

## ITEM 1A. RISK FACTORS.

*Certain risks and uncertainties that could have a material impact on PGE's business, financial condition, results of operations, or cash flows, or that may cause the Company's actual results to vary materially from the forward-looking statements contained in this Annual Report on Form 10-K, include those set forth below.*

### *REGULATORY, LEGAL, AND COMPLIANCE RISKS*

**PGE is subject to extensive regulation that affects the Company's operations and costs.**

PGE is subject to regulation by the FERC, the OPUC, and by certain federal, state, and local authorities under environmental and other laws. Such regulation significantly influences the Company's operating environment and can have an effect on many aspects of its business. Changes to regulations are ongoing, and the Company cannot predict with certainty the future course of such changes or the ultimate effect that they might have on its business. However, changes in regulations could delay or adversely affect business planning and transactions, and substantially increase the Company's costs.

**Recovery of PGE's costs is subject to regulatory review and approval, and the inability to recover costs may adversely affect the Company's results of operations.**

The prices that PGE charges for its retail services, as authorized by the OPUC, are a major factor in determining the Company's operating income, financial position, liquidity, and credit ratings. As a general matter, PGE seeks to recover in customer prices most of the costs incurred in connection with the operation of its business, including, among other things, costs related to capital projects (such as the construction of new facilities or the modification of existing facilities), the costs of compliance with legislative and regulatory requirements, and the costs of damage from storms and other natural disasters. However, there can be no assurance that such recovery will be granted. The OPUC has the authority to disallow the recovery of any costs that it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just and reasonable, it has significant discretion in the interpretation of this standard.

PGE attempts to manage its costs at levels consistent with the OPUC approved prices. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Company's financial and operating results could be adversely affected.

**PGE is subject to various legal and regulatory proceedings, the outcome of which is uncertain, and resolution unfavorable to PGE could adversely affect the Company's results of operations, financial condition, or cash flows.**

In the normal course of its business, PGE is subject to various regulatory proceedings, lawsuits, claims, and other matters, which could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. These matters are subject to many uncertainties, the ultimate outcome of which management cannot predict. The final resolution of certain matters in which PGE is involved could require that the Company incur expenditures over an extended period of time and in a range of amounts that could have an adverse effect on its cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse effect on its cash flows, financial position, or results of operations.

There are certain pending legal and regulatory proceedings that may have an adverse effect on results of operations and cash flows for future reporting periods. For additional information, see Item 3.—"Legal Proceedings" and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

**Legislative or regulatory efforts to reduce GHG emissions could lead to increased capital and operating costs and have an adverse impact on the Company's results of operations.**

Future legislation or regulations could result in limitations on GHG emissions from the Company's fossil fuel-fired generation facilities. Compliance with any GHG emissions reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the replacement of high-emitting generation facilities with lower-emitting facilities.

The cost to comply with potential GHG emissions reduction requirements is subject to significant uncertainties, including those related to: i) the timing of the implementation of emissions reduction rules; ii) required levels of emissions reductions; iii) requirements with respect to the allocation of emissions allowances; iv) the maturation, regulation, and commercialization of carbon capture and sequestration technology; and v) PGE's compliance alternatives. Although the Company cannot currently estimate the effect of future legislation or regulations on its results of operations, financial condition, or cash flows, the costs of compliance with such legislation or regulations could be material.

**Operational changes required to comply with both existing and new environmental laws related to fish and wildlife could adversely affect PGE's results of operations.**

A portion of PGE's total system load is supplied with power generated from hydroelectric and wind generating resources. Operation of these facilities is subject to regulation related to the protection of fish and wildlife. The listing of various plants and species of fish, birds, and other wildlife as threatened or endangered has resulted in significant operational changes to these projects. Salmon recovery plans could include further major operational changes to the region's hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission and distribution lines and wind projects. Also, new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the availability of hydroelectric or wind generating resources to meet the Company's energy requirements.

**The construction of new facilities, or modifications to existing facilities, is subject to risks that could result in the disallowance of certain costs for recovery in customer prices or higher operating costs.**

PGE supplements its own generation with wholesale power purchases to meet its retail load requirement. In addition, long-term increases in both the number of customers and demand for energy will require continued expansion and upgrade of PGE's generation, transmission, and distribution systems. Construction of new facilities and modifications to existing facilities could be affected by various factors, including unanticipated delays and cost increases and the failure to obtain, or delay in obtaining, necessary permits from state or federal agencies or tribal entities, which could result in failure to complete the projects and the disallowance of certain costs in the rate determination process. In addition, failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs.

***ECONOMIC, FINANCIAL, AND MARKET RISKS***

**Economic conditions that result in reduced demand for electricity and impair the financial stability of some of PGE's customers could affect the Company's results of operations.**

Unfavorable economic conditions in Oregon may result in reduced demand for electricity. Such reductions in demand could adversely affect PGE's results of operations and cash flows. Economic conditions could also result in an increased level of uncollectible customer accounts and cause the Company's vendors and service providers to experience cash flow problems and be unable to perform under existing or future contracts.

**Capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan as currently envisioned.**

Access to capital and credit markets is important to PGE's ability to operate. The Company expects to issue debt and equity securities, as necessary, to fund its future capital requirements. In addition, contractual commitments and regulatory requirements may limit the Company's ability to delay or terminate certain projects.

If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Company's future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, restrictions on PGE's ability to access capital markets could affect its ability to execute its strategic plan.

**Adverse changes in PGE's credit ratings could negatively affect its access to the capital markets and its cost of borrowed funds.**

Access to capital markets is important to PGE's ability to operate its business and complete its capital projects. Credit rating agencies evaluate the Company's credit ratings on a periodic basis and when certain events occur. A ratings downgrade could increase fees on PGE's revolving credit facilities and letter of credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Company's access to the commercial paper market, a principal source of short-term financing, or result in higher interest costs.

In addition, if Moody's Investors Service (Moody's) and/or S&P Global Ratings (S&P) reduce their rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Company's liquidity.

**Under certain circumstances, banks participating in PGE's credit facilities could decline to fund advances requested by the Company or could withdraw from participation in the credit facilities.**

PGE currently has a syndicated unsecured revolving credit facility with several banks for an aggregate amount of $500 million. The revolving credit facility provides a primary source of liquidity and may be used to supplement operating cash flow and as backup for commercial paper borrowings. The revolving credit facility represents commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under the credit facility. However, in the event certain circumstances occur that could result in a material adverse change in the business, financial condition, or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facility.

**Adverse capital market performance could result in reductions in the fair value of benefit plan assets and increase the Company's liabilities related to such plans. Sustained declines in the fair value of the plans' assets could result in significant increases in funding requirements, which could adversely affect PGE's liquidity and results of operations.**

Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under PGE's defined benefit pension and other postretirement plans. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGE's funding requirements related to the plans. Additionally, changes in interest rates affect PGE's liabilities under the plans. As interest rates decrease, the Company's liabilities increase, potentially requiring additional funding.

Performance of the capital markets also affects the fair value of assets that are held in trust to satisfy future obligations under the Company's non-qualified employee benefit plans, which include deferred compensation plans. As changes in the fair value of these assets are recorded in current earnings, decreases can adversely affect the Company's operating results. In addition, such decreases can require that PGE make additional payments to satisfy its obligations under these plans.

**Market prices for power and natural gas are subject to forces that are often not predictable and that can result in price volatility and general market disruption, adversely affecting PGE's costs and ability to manage its energy portfolio and procure required energy supply, which ultimately could have an adverse effect on the Company's liquidity and results of operations.**

As part of its normal business operations, PGE purchases and sells power and natural gas in the open market under short- and long-term contracts, which may specify variable prices or volumes. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric and wind generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology.

Volatility in these markets can affect the availability, price, and demand for power and natural gas. Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect regulatory and legislative processes in unpredictable ways, affect wholesale power prices, and impair PGE's ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the fair value of derivative instruments and cash requirements to purchase power and natural gas. If power and natural gas prices decrease from those contained in the Company's existing purchased power and natural gas agreements, PGE may be required to provide increased collateral, which could adversely affect the Company's liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated.

The risk of volatility in power costs is partially mitigated through the AUT and the PCAM. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices.

***BUSINESS AND OPERATIONAL RISKS***

***The spread of COVID-19 could have a material adverse effect on PGE's business.***

The COVID-19 pandemic has adversely impacted economic activity and conditions worldwide. Measures to control the spread of COVID-19 have affected the demand for the products and services of many businesses in PGE's service territory and disrupted supply chains around the world. Due to COVID-19, PGE has observed an increase in past due accounts and late customer payments resulting in incremental bad debt expense of $8 million in 2020 that has been deferred pursuant to the OPUC's COVID-19 deferral. PGE has also observed a change in the trend of customer demand with an increase in residential usage as customers stay at home and a decrease in commercial usage due to COVID-19 related closures and economic conditions. Although these trends have not had a material impact on the Company to date, management believes that these trends will continue and the full scope and extent of the impacts of COVID-19 on the Company's operations remains uncertain and depends on multiple variables. PGE continues to monitor the impacts of the COVID-19 pandemic on its workforce, liquidity, capital markets, reliability, cybersecurity, customers, and suppliers, along with overall macroeconomic conditions. Although the Company cannot predict with certainty the full extent of the COVID-19 pandemic's impact on its business, a protracted slowdown of broad sectors of the economy, changes in demand for commodities, or significant changes in legislation or regulatory policy to address the COVID-19 pandemic could ultimately result in a significant reduction in demand for electricity in PGE's service territory, increased late customer payments or uncollectible accounts, and the inability of the Company’s contractors, suppliers, and other business partners to fulfill their contractual obligations, any of which could have, or continue to have, a material adverse effect on the Company’s results of operations, financial condition and cash flows.

**Changes in tax laws may have an adverse impact on the Company’s financial position, results of operations, and cash flows.**

PGE makes judgments and interpretations about the application of tax law when determining the provision for taxes. Such judgments include the timing and probability of recognition of income, deductions, and tax credits, which are subject to challenge by taxing authorities. Additionally, treatment of tax benefits and costs for ratemaking purposes could be different than what the Company anticipates or requests from the state regulatory commission, which could have a negative effect on the Company’s financial condition and results of operations.

PGE owns and operates wind generating facilities, which generate federal production tax credits (PTCs) that PGE uses to reduce its federal tax obligations. The amount of PTCs earned depends on the level of electricity output generated and the applicable tax credit rate. A variety of operating and economic parameters, including adverse weather conditions and equipment reliability, could significantly reduce the PTCs generated by the Company’s wind facilities resulting in a material adverse impact on PGE’s financial condition and results of operations. These PTCs generate tax credit carryforwards that the Company plans to utilize in the future to reduce income tax obligations. If PGE cannot generate enough taxable income in the future to utilize all of the tax credit carryforwards before the credits expire, the Company may incur material charges to earnings.

**The effects of weather on electricity usage can adversely affect results of operations.**

Weather conditions can adversely affect PGE’s revenues and costs, impacting the Company’s results of operations. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winter seasons or cooler-than-normal summer seasons reducing the demand for energy. Weather conditions are the dominant cause of usage variations from normal seasonal patterns, particularly for residential customers. Severe weather can also disrupt energy delivery and damage the Company’s transmission and distribution system.

Rapid increases in load requirements resulting from unexpected weather changes, particularly if coupled with transmission constraints, could adversely impact PGE’s cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices.

**Reduced river flows can adversely affect generation from hydroelectric resources and unfavorable wind conditions can similarly affect wind generating resources. The Company could be required to replace energy expected from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on results of operations.**

PGE derives a significant portion of its power supply from its own hydroelectric facilities and through long-term purchase contracts with certain public utility districts in the state of Washington. Regional rainfall and snowpack levels affect river flows and the resulting amount of energy generated by these facilities. Shortfalls in energy expected from lower cost hydroelectric generating resources would require increased energy from the Company’s other generating resources and/or power purchases in the wholesale market, which could have an adverse effect on results of operations.

PGE also derives a portion of its power supply from wind generating resources, for which the output is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Company’s thermal generating resources or power purchases in the wholesale market, both of which could have an adverse effect on results of operations.

Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power provided by hydroelectric and wind generating resources, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future prices could have a negative impact on the Company's results of operations, as well as a reduction in renewable energy credits and loss of PTCs related to wind generating resources.

**Storms, earthquakes, wildfires, and other natural disasters could damage the Company's facilities and disrupt delivery of electricity resulting in significant property loss, repair costs, and reduced customer satisfaction.**

PGE has exposure to natural disasters that can cause significant damage to its generation, transmission, and distribution facilities. Such events can interrupt the delivery of electricity, increase repair and service restoration expenses, and reduce revenues. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. As a regulated utility, the Company is required to provide service to all customers within its service territory and generally has been afforded liability protection against customer claims related to service failures beyond the Company's reasonable control.

**PGE could be vulnerable to cybersecurity attacks, data security breaches, acts of terrorism, or other similar events that could disrupt its operations, require significant expenditures, or result in claims against the Company.**

In the normal course of business, PGE collects, processes, and retains sensitive and confidential customer and employee information, as well as proprietary business information, and operates systems that directly impact the availability of electric power and the transmission of electric power in its service territory. Despite the security measures in place, the Company's systems, and those of third-party service providers, could be vulnerable to cybersecurity attacks, data security breaches, acts of terrorism, or other similar events that could disrupt operations or result in the release of sensitive or confidential information. Such events could cause a shutdown of service or expose PGE to liability. In addition, the Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches. PGE maintains insurance coverage against some, but not all, potential losses resulting from these risks. However, insurance may not be adequate to protect the Company against liability in all cases. In addition, PGE is subject to the risk that insurers will dispute or be unable to perform their obligations to the Company.

**Forced outages at PGE's generating plants can increase the cost of power required to serve customers because the cost of replacement power purchased in the wholesale market generally exceeds the Company's cost of generation.**

Forced outages at the Company's generating plants could result in power costs greater than those included in customer prices. As indicated above, application of the Company's PCAM could help mitigate adverse financial impacts of such outages; however, the cost sharing features of the mechanism do not provide full recovery in customer prices. Inability to recover such costs in future prices could have a negative impact on the Company's results of operations.

**Development of alternative technologies may negatively impact the value of PGE's generation facilities.**

A basic premise of PGE's business is the ability to produce electricity at competitive prices due to economies of scale. Many companies and organizations conduct research and development activities to seek improvements in alternative technologies and distributed generation. It is possible that advances in such technologies, or other current technologies, will reduce the cost of alternative methods of electricity production to a level that is equal to or below that of existing generation facilities. Such a development could limit the Company's future growth opportunities and limit growth in demand for PGE's electric service.

**The inability to attract and retain a qualified workforce, including senior management talent, and to maintain satisfactory collective bargaining agreements without prolonged labor disruptions, may adversely affect PGE's results of operations.**

PGE's workforce includes a diverse mix of skilled professional, managerial and technical employees, including employees represented under collective bargaining agreements. Workforce management risks include the risk of turnover due to demographic challenges as employees approach retirement age. PGE also faces competition from other employers for key skills and experience within the industry or local geography. The Company also faces the risk of labor disruption due to the outcomes of labor negotiations or the possibility that employees not currently subject to collective bargaining agreements may organize.

**PGE business activities are concentrated in one region and future performance may be affected by events and factors unique to Oregon.**

The Company's industry and geographic concentrations may increase exposure to risks arising from regional regulation or legislation, such as legislative action related to carbon emissions. These concentrations may also increase exposure to credit and operational risks due to counterparties, suppliers, and customers being similarly affected by changing conditions.

## ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

## ITEM 2. PROPERTIES.

PGE's principal property, plant, and equipment are generally located on land owned by the Company or land under the control of the Company pursuant to existing leases, federal or state licenses, easements, or other agreements. In some cases, meters and transformers are located on customer property. The Indenture securing the Company's First Mortgage Bonds (FMBs) constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property.

### *Generating Facilities*

The following are generating facilities owned by PGE as of December 31, 2020 (in MW):

| Facility | Location | Net Capacity (1) |
|---|---|---|
| **Wholly-owned:** | | |
| *Natural Gas or Oil:* | | |
| Beaver | Clatskanie, Oregon | 508 |
| Carty | Boardman, Oregon | 438 |
| Port Westward Unit 1 (PW1) | Clatskanie, Oregon | 411 |
| Coyote Springs | Boardman, Oregon | 249 |
| Port Westward Unit 2 (PW2) | Clatskanie, Oregon | 225 |
| *Wind:* | | |
| Biglow Canyon | Sherman County, Oregon | 450 |
| Tucannon River | Columbia County, Washington | 267 |
| Wheatridge | Morrow County, Oregon | 100 |
| *Hydro:* | | |
| North Fork | Clackamas River | 58 |
| Faraday | Clackamas River | 46 |
| Oak Grove | Clackamas River | 45 |
| River Mill | Clackamas River | 25 |
| T.W. Sullivan | Willamette River | 18 |
| **Jointly-owned (2):** | | |
| *Coal:* | | |
| Colstrip (3) | Colstrip, Montana | 296 |
| *Hydro:* | | |
| Round Butte (4) | Deschutes River | 230 |
| Pelton (4) | Deschutes River | 73 |
| Net capacity | | 3,439 |

(1) Represents net capacity of generating unit as demonstrated by actual operating or test experience, net of electricity used in the operation of a given facility. For wind-powered generating facilities, nameplate ratings are used in place of net capacity. A generator's nameplate rating is its full-load capacity under normal operating conditions as defined by the manufacturer.
(2) Net capacity reflects PGE's ownership share.
(3) PGE has a 20% ownership interest in the facility, which is operated by Talen Montana, LLC. The Company operated, and continues to have a 90% ownership interest in, Boardman, which ceased coal-fired operations during the fourth quarter of 2020.
(4) PGE operates Pelton and Round Butte and has a 66.67% ownership interest.

PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the FPA. The licenses for the hydroelectric projects on the three different rivers expire as follows: Clackamas River, 2055; Willamette River, 2035; and Deschutes River, 2055.

***Transmission and Distribution***

PGE owns or has contractual rights associated with transmission lines that deliver electricity from its generation facilities to its distribution system in its service territory and also to the Western Interconnection. As of December 31, 2020, PGE-owned electric transmission system consisted of 1,269 circuit miles as follows: 287 circuit miles of 500 kV line; 414 circuit miles of 230 kV line; and 568 miles of 115 kV line. The Company also has 27,939 circuit miles of distribution lines that deliver electricity to its customers. The Company also has an ownership interest in, and capacity on, the following:

- 15% of the Colstrip Transmission facilities from Colstrip to BPA's transmission system; and

- 20% of the Pacific Northwest Intertie, a 4,800 MW transmission facility between the John Day Substation near the Columbia River in northern Oregon, and Malin, Oregon, near the California border. The Pacific Northwest Intertie is used primarily for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

In addition, the Company has contractual rights to the following transmission capacity:

- 4,045 MW of firm BPA transmission on BPA's system to PGE's service territory in Oregon; and
- 150 MW of firm BPA transmission from the Mid-Columbia projects in Washington to the northern end of the Pacific Northwest AC Intertie, near John Day, Oregon, 5 MW to Tucannon River, and 5 MW to Biglow Canyon.

## ITEM 3. LEGAL PROCEEDINGS.

See Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data," for information regarding legal proceedings.

## ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

# PART II

## ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

PGE's common stock is traded on the NYSE under the ticker symbol "POR". As of February 10, 2021, there were 653 holders of record of PGE's common stock.

While the Company expects to pay regular quarterly dividends on its common stock, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration will depend upon factors that the Board of Directors deems relevant and may include, but are not limited to, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

For information with respect to securities authorized for issuance under equity compensation plans, see Note 14, Stock-Based Compensation in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

### Share repurchase program

On February 17, 2021, the Company's Board of Directors authorized a share repurchase program, under which the Company is authorized to repurchase up to $17.5 million of its outstanding common stock through 2022. The share repurchase program may be limited or terminated at any time without prior notice. Under the share repurchase program, the Company may repurchase shares of common stock from time to time in open market transactions or in privately negotiated transactions as permitted under applicable rules and regulations. The extent to which the Company repurchases its shares of common stock and the timing of such purchases will depend upon market conditions and other considerations as may be determined in the Company's sole discretion. Repurchases may also be made pursuant to a trading plan under Rule 10b5-1 under the Securities Exchange Act of 1934, as amended, which would permit shares to be repurchased when the Company might otherwise be precluded from doing so because of self-imposed trading blackout periods or other regulatory restrictions. The Company intends to finance any repurchases under the share repurchase program using cash on hand.

## ITEM 6. [REMOVED AND RESERVED]

## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

***Forward-Looking Statements***

The information in this report includes statements that are forward-looking within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements include, but are not limited to, statements that relate to expectations, beliefs, plans, assumptions and objectives concerning future results of operations, business prospects, loads, outcome of litigation and regulatory proceedings, capital expenditures, market conditions, future events or performance, and other matters. Words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," "should," or similar expressions are intended to identify such forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis including, but not limited to, management's examination of historical operating trends and data contained either in internal records or available from third parties, but there can be no assurance that PGE's expectations, beliefs, or projections will be achieved or accomplished.

In addition to any assumptions and other factors and matters referred to specifically in connection with forward-looking statements, factors that could cause actual results or outcomes for PGE to differ materially from those discussed in such forward-looking statements include:

- governmental policies, legislative action, and regulatory audits, investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;
- economic conditions that result in decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;
- changing customer expectations and choices that may reduce customer demand for its services may impact PGE's ability to make and recover its investments through rates and earn its authorized return on equity, including the impact of growing distributed and renewable generation resources, changing customer demand for enhanced electric services, and an increasing risk that customers procure electricity from registered ESSs or community choice aggregators;
- the outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K;
- unseasonable or extreme weather and other natural phenomena, which could affect customers' demand for power and PGE's ability and cost to procure adequate power and fuel supplies to serve its customers, and could increase the Company's costs to maintain its generating facilities and transmission and distribution systems;
- operational factors affecting PGE's power generating facilities, including forced outages, hydro and wind conditions, and disruption of fuel supply, any of which may cause the Company to incur repair costs or purchase replacement power at increased costs;

- complications arising from PGE's jointly-owned generating facilities, including changes in ownership, adverse regulatory outcomes or legislative actions, or operational failures that result in legal or environmental liabilities or unanticipated costs related to replacement power or repair costs;
- failure to complete capital projects on schedule and within budget or the abandonment of capital projects, either of which could result in the Company's inability to recover project costs;
- volatility in wholesale power and natural gas prices that could require PGE to post additional collateral or issue additional letters of credit pursuant to power and natural gas purchase agreements;
- changes in the availability and price of wholesale power and fuels, including natural gas and coal, and the impact of such changes on the Company's power costs;
- capital market conditions, including availability of capital, volatility of interest rates, reductions in demand for investment-grade commercial paper, as well as changes in PGE's credit ratings, any of which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction of capital projects, and the repayments of maturing debt;
- future laws, regulations, and proceedings that could increase the Company's costs of operating its thermal generating plants, or affect the operations of such plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generating facilities, in order to mitigate carbon dioxide, mercury and other gas emissions;
- changes in, and compliance with, environmental laws and policies, including those related to threatened and endangered species, fish, and wildlife;
- the effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company's costs, or adversely affect its operations;
- changes in residential, commercial, or industrial customer growth, or demographic patterns, in PGE's service territory;
- the effectiveness of PGE's risk management policies and procedures;
- cybersecurity attacks, data security breaches, or other malicious acts that cause damage to the Company's generation, transmission, or distribution facilities, information technology systems, or result in the release of confidential customer, employee, or Company information;
- employee workforce factors, including potential strikes, work stoppages, transitions in senior management, and the ability to recruit and retain appropriate talent;
- new federal, state, and local laws that could have adverse effects on operating results;
- political and economic conditions;
- natural disasters and other risks, such as pandemic, earthquake, flood, drought, lightning, wind, and fire;
- the impact of widespread health developments, including the global coronavirus (COVID–19) pandemic, and responses to such developments (such as voluntary and mandatory quarantines, including government stay at home orders, as well as shut downs and other restrictions on travel, commercial, social, and other activities), which could materially and adversely affect, among other things, demand for electric services, customers' ability to pay, supply chains, personnel, contract counterparties, liquidity and financial markets;
- changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- acts of war or terrorism; and
- the impact of the recommendations on the Company and its operations based on the review conducted by the Special Committee relating to energy trading losses, the time and expense incurred in implementing the recommendations of the Special Committee, and any reputational damage to the Company relating to the matters underlying the Special Committee's review.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, PGE undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors or assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

## OVERVIEW

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide an understanding of the business environment, results of operations, and financial condition of PGE. MD&A should be read in conjunction with the Company's consolidated financial statements contained in this report, and other periodic and current reports filed with the SEC.

PGE is a vertically-integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity in the state of Oregon, as well as the wholesale purchase and sale of electricity and natural gas in order to meet the needs of its retail customers. The Company generates revenues and cash flows primarily from the sale and distribution of electricity to retail customers in its service territory. In addition, the Company 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.

### Energy Trading

PGE is exposed to commodity price risk as its primary business is to provide electricity to its retail customers. The Company expects to manage commodity price volatility within net variable power costs by engaging in energy trading activities. The Company does not intend to engage in trading activities for non-retail purposes.

PGE personnel entered into a number of energy trades during 2020, with increasing volume accumulating late in the second quarter and into the third quarter, resulting in significant exposure to the Company. In August 2020, a portion of energy trading positions in PGE's energy portfolio experienced significant losses as wholesale electricity prices increased substantially at various market hubs due to extreme weather conditions, constraints to regional transmission facilities, and changes in power supply in the West. During this time period, the CAISO declared a Stage 3 Electrical Emergency and ordered the first rolling blackouts in the state of California since 2001.

As a result of the convergence of these conditions, the Company's energy portfolio experienced realized losses of $127 million on these positions in 2020. PGE determined the energy trading positions that led to the losses were outside the Company's acceptable risk tolerances, and the Company will not pursue regulatory recovery of the associated losses. PGE will also exclude the impacts of the realized losses from its regulatory earnings tests. The increase in net variable power costs due to this trading activity has been recognized in PGE's results of operations. PGE no longer has net market exposure from the energy trading positions that led to these losses.

PGE and its external consultants have performed a full operational review of the Company's energy supply risk management policies, procedures and personnel. In addition, the PGE Board of Directors formed a Special Committee comprising five independent Board members to review the energy trading that led to the losses and the Company's procedures and controls related to the trading, and to make recommendations to the Board for appropriate action. The Special Committee retained independent legal advisors. On December 18, 2020, PGE announced that the Special Committee concluded its independent review of the energy trading activity that led to the losses incurred in the third quarter of 2020. The Special Committee concluded that the trades were ill-conceived and revealed opportunities for improving the Company's energy trading policies and practices. Additionally, the Board of Directors concluded that the actions the Company began taking in August to enhance oversight of energy trading and associated risk management reporting, policies, and practices were consistent with the Special Committee's recommendations and will be monitored by the Board of Directors through enhanced reporting. These actions are expected to strengthen the Company and include:

- *Added expertise*: PGE brought in additional experienced risk management personnel and replaced the Power Operations general manager with a new leader;
- *Strengthened trading policies*: Power Operations personnel are operating under revised policies designed to prevent positions of the type that led to the losses. The improved policies place controls on the ability of personnel to enter into wholesale energy transactions to the extent that PGE does not have physical or financial delivery capability;
- *Enhanced risk reporting*: Energy trading activity reporting has been improved to ensure greater visibility into portfolio risk;
- *Changed reporting structures*: Energy Trading Risk Management now reports through a Risk and Compliance team that reports to the Chief Executive Officer. Effective January 1, 2021, Power Operations reports to the Vice President of Strategy, Regulation and Energy Supply; and
- *Changed personnel*: The individuals who previously were placed on leave are no longer with the Company.

For further information regarding legal proceedings associated with this matter, see "Shareholder Lawsuits" in Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

**COVID-19 Impacts**

The COVID-19 pandemic has adversely impacted economic activity and conditions worldwide, including workforces, liquidity, capital markets, consumer behavior, supply chains, and macroeconomic conditions. In the state of Oregon, the Governor issued an executive order on March 23, 2020 directing Oregon residents to stay at home except for essential activity and mandating closure of businesses for which close personal contact was difficult or impossible to avoid. This order was rescinded May 14, 2020 in a new executive order announcing a phased approach for reopening Oregon's economy. The subsequent phased reopening approach has not allowed all businesses to reopen, or has allowed reopening only at reduced capacity to meet requirements for social distancing. The continued loosening of restrictions is contingent upon the successful reduction of cases.

*Retail loads*—The slowdown in certain sectors of the economy due to COVID-19 and the initial stay-at-home order and subsequent phased reopening plans has resulted in changes in retail load patterns. See "*Customers and Demand*" and "*Decoupling*" in this Overview section and "*Revenues*" of the Results of Operations section for more information related to COVID-19 impacts on retail loads and Revenues, net.

*Bad debt expense*—The Company has responded to the hardships many customers are facing and has taken steps to support its customers and communities, including temporarily suspending disconnections and late fees during the crisis, developing time payment arrangements, and partnering with local non-profits to soften the impacts on small businesses and low-income residential customers. PGE's bad debt expense was $15 million for the full-year 2020, compared to an original $6 million forecast, subject to deferral. See "*Administrative and other*" of the Results of Operations section for more information related to COVID-19 impacts on bad debt expense, and see "*Legislative and regulatory developments"* within this Overview section for more information regarding regulatory deferrals of incremental costs associated with the COVID-19 pandemic.

*Financial condition and liquidity*—Global capital markets have experienced significant volatility in response to COVID-19 and PGE continues to assess the impact of this volatility on its liquidity position and capital investment plans. The Company believes the combination of its revolver capacity, proceeds of a $150 million, 364-day term loan, issued in April 2020, and proceeds from $200 million and $230 million FMB issuances, in April and November 2020, respectively, will continue to provide adequate liquidity for the Company's operational needs. The Company continues to evaluate its five-year capital plan. A detailed discussion of capital market and capital investment responses is included in the Liquidity and Capital Resources section of this Item 7.

The COVID-19 pandemic did not have a material impact on PGE's financial condition and cash flows in 2020 and the Company continues to have sufficient liquidity to meet the Company's anticipated capital and operating requirements going forward. It is reasonably possible, however, that disruption and volatility in the global capital markets may materially increase the cost of capital.

*Supply chain*—The global nature of the COVID-19 pandemic has resulted in supply chain disruptions and in some instances construction interruptions, although PGE has not experienced significant supply chain disruptions or construction interruptions to date. The Company's business continuity plans have included an assessment of critical operational supply chain linkages and an assessment of potential interruptions to its capital project execution. The Company will continue to monitor supply chain issues, including possible force majeure notices, for any material impacts to its operations.

*Business continuity plans*—In February 2020, as more information about the potential impacts of COVID-19 became available, the Company activated its business continuity plans. These plans are designed to ensure the safety of the public and employees while the Company continues to provide critical service to its customers. In addition to directing employees to work from home when appropriate, the Company has implemented safeguards for employees who play critical roles to ensure operational reliability and established protocols for employees who interact directly with the public. The Company has enacted extra physical security and cybersecurity measures to safeguard systems to serve operational needs, including those of its remote workforce, and to ensure uninterrupted service to customers. The Company will continue to evolve its business continuity plans to follow guidance from the Centers for Disease Control and the Oregon Health Authority. Although PGE has plans in place to address workforce availability, including sequestration of key employees if necessary, the Company has not experienced workforce availability issues to date. Implementation of PGE's business continuity plans have not had a material impact on PGE's results of operation.

*Legislative and regulatory developments*—The Company has analyzed available relief for the economic effects of COVID-19 under the following:

- FERC Waiver—On June 30, 2020 the FERC issued a waiver that provides that, for the 12-month period starting March 2020, jurisdictional utilities may apply an alternative allowance for funds used during construction (AFDC) calculation formula that excludes the actual outstanding short-term debt balance and replaces it with the simple average of the actual 2019 short-term debt balance. The purpose of the waiver is to allow relief from the detrimental impacts of issuing short-term debt on the allowance for equity funds used during construction. PGE adopted the waiver in the second quarter of 2020 and retrospectively applied its provisions as of March 2020, resulting in a $1 million increase to AFDC. The Company continues to monitor for potential extensions of the waiver beyond the original 12-month period.

- Coronavirus Aid, Relief, and Economic Security (CARES) Act—On March 27, 2020, the U.S. Government enacted the CARES Act, which provides economic relief and stimulus to support the national economy during the COVID-19 pandemic and includes support for individuals, large corporations, small business, and health care entities, among other affected groups. The Company has not experienced direct material benefits from the CARES Act.

- COVID-19 Deferral—PGE filed an application for deferral of certain incremental costs and lost revenue related to COVID-19 on March 20, 2020 with the OPUC. The application requested the ability to defer incremental costs associated with the COVID-19 pandemic but did not specify the precise scope of the deferral, or the means by which PGE would recover deferred amounts. PGE, other utilities under the OPUC's jurisdiction, intervenors, and OPUC staff held discussions regarding the scope of costs incurred by utilities that may qualify for deferral under Docket UM 2114, *Investigation into the Effects of the COVID-19 Pandemic on Utility Customers*. The result of such discussions was an Energy Term Sheet (Term Sheet), which dictates costs in scope for deferral, but is silent to the timing of recovery of such costs. On September 24, 2020, the Commission adopted OPUC Staff's motion to execute stipulations incorporating the terms of the Term Sheet. PGE's deferral application was approved by the Commission on October 20, 2020 with final stipulations for the Term Sheet approved on November 3, 2020. As of December 31, 2020, PGE has deferred $8 million related to bad debt expense, and $2 million for other incremental costs associated with COVID-19 under the Term Sheet. All other incremental expenses will be recognized in the results of operations, until a determination is made that cost recovery is probable.

Amortization of any deferred costs will remain subject to OPUC review prior to amortization and inclusion in customer prices. Although PGE expects its 2020 regulated ROE, after adjusting for certain energy trading losses, to exceed its authorized ROE of 9.5%, PGE believes the full amount of the 2020 deferral is probable of recovery as the Company's prudently incurred costs were in response to the unique nature of the COVID-19 pandemic health emergency. The OPUC has significant discretion in making the final determination of recovery and their conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE's 2020 deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

**Company Strategy**

PGE is committed to continuing to achieve steady growth and returns as the Company transforms to meet the challenges of climate change and an ever-evolving energy grid. Customers, policy makers, and other stakeholders expect PGE to reduce GHG emissions, keep the power grid reliable and secure, and ensure prices are affordable, especially for the most vulnerable customers. The Company's strategy strives to balance these interests. PGE plans to:

- Reduce GHG emissions associated with the power served to customers by 80% by 2030 (2010 baseline year), and setting an aspirational goal for zero GHG emissions associated with the power served to customers by 2040;
- Electrify sectors of the economy like transportation and buildings that are also transforming to reduce GHG emissions; and
- Perform as a business, driving improvements to work efficiency, safety of our coworkers, and reliability of our systems and equipment all while adhering to the Company's earnings per diluted share growth guidance of 4-6% on average.

**Decarbonize the power supply**—PGE partners with customers and local and state governments to advance a clean energy future. PGE continues to leverage these partnerships to pursue emission reductions using a diverse portfolio of clean and renewable energy resources, and promote economy-wide emission reductions through electrification and smart energy use to help the state meet its GHG emission reduction goals. In addition to state greenhouse gas reduction goals, PGE announced in 2020 a new company wide goal of achieving net zero GHG emissions by 2040. PGE also announced a new goal to meet customer expectations for clean energy, pledging to reduce GHG emissions associated with the power served to customers by 80% by 2030 (2010 baseline year).

To reach these goals, PGE will focus on the following areas:

*Customer Choice Programs*—PGE's customers continue to express a commitment to purchasing clean energy, as over 230,000 customers voluntarily participate in PGE's Green Future Program, the largest renewable power program by participation in the nation. In 2017, Oregon's most populous city, Portland, and most populous county, Multnomah, each passed resolutions to achieve 100 percent clean and renewable electricity by 2035 and 100 percent economy-wide clean and renewable energy by 2050. Other jurisdictions in PGE's service area continue to consider similar goals.

In response, the Company has implemented a new customer product option, the Green Future Impact program, which allows for 100 MW of PGE-provided power purchase agreements for renewable resources and up to 200 MW of customer-provided renewable resources. Approved by the OPUC in the first quarter 2019, the program will provide business customers access to bundled renewable attributes from those resources. Through this voluntary program, the Company seeks to align sustainability goals, cost and risk management, reliable integrated power, and a cleaner energy system.

Pursuant to the OPUC order approving the Green Future Impact tariff, program subscribers remain cost of service customers, and pay both the cost of service tariff price and the price under the renewable energy option tariff. This structure is intended to avoid stranded costs and cost shifting.

*Carbon Legislation and Administrative Actions*—In 2016, SB 1547 set a benchmark for how much electricity must come from renewable sources like wind and solar and requires the elimination of coal from Oregon utility customers' energy supply no later than 2030 (subject to an exception that allows extension of this date until 2035 for PGE's output from Colstrip).

Other provisions of the law include:

- An increase in RPS thresholds to 27% by 2025, 35% by 2030, 45% by 2035, and 50% by 2040;
- A limitation on the life of Renewable Energy Credits (RECs) generated from facilities that become operational after 2022 to five years, but continued unlimited lifespan for all existing RECs and allowance for the generation of additional unlimited RECs for a period of five years for projects online before December 31, 2022; and
- An allowance for energy storage costs related to renewable energy in the Company's RAC filings.

In response to SB 1547, the Company filed a tariff request in 2016 to accelerate recovery of PGE's investment in the Colstrip facility from 2042 to 2030. In January 2020, the owners of Colstrip Units 1 and 2 permanently retired those two units. Although PGE has no direct ownership interest in Units 1 and 2, the Company does have a 20% ownership share in Colstrip Units 3 and 4, which utilize certain common facilities with Units 1 and 2.

Although PGE is currently scheduled to recover the costs of Colstrip by 2030, some co-owners of Units 3 and 4 have sought approval to recover their costs sooner in their respective jurisdictions. In its most recent depreciation study filed with the OPUC in January 2021, PGE proposed to accelerate depreciation on Colstrip generation assets through 2027. The Company continues to evaluate its ongoing investment in Colstrip, including the possibility of earlier closure of these facilities.

Any reduction in generation from Colstrip has the potential to provide capacity on the Colstrip transmission facilities, which stretches from eastern Montana to near the western end of the state to serve markets in the Pacific Northwest and beyond. PGE has a 15% ownership interest in, and capacity on, the Colstrip Transmission facilities. Renewable energy development in the state of Montana could benefit from any excess transmission capacity that may become available.

As previously planned, in October 2020, PGE ceased coal-fired operation at Boardman and has begun decommissioning activities.

During the 2019 Oregon legislative session, House Bill (HB) 2020 was introduced, which would have authorized a comprehensive cap and trade package in Oregon and would have granted the OPUC direct authority to address climate change. Although HB 2020 was not enacted in 2019, an amended version was reintroduced in the 35-day legislative session, which began in February 2020. This new proposal, SB 1530, was also a cap and trade package that included changes made to address concerns raised by various parties. Prior to the legislative session, the OPUC stated that it would continue to collaborate with the legislature and stakeholders to make progress on climate change, noting that their authority was limited to that of an economic regulator.

The short 2020 legislative session adjourned without action on SB 1530 and, as a result, in March 2020, the Governor of Oregon issued an executive order directing state agencies to seek to reduce and regulate GHG emissions. Many of the direct agency actions are on an aggressive timeline with due dates in 2020 and 2021. As the Governor is limited by current statutory authority, the executive order does not include a market-based mechanism as envisioned by the cap and trade legislation introduced in the 2019 and 2020 legislative sessions.

Among other things, the executive order:

- Modified the statewide GHG emissions reduction goals to at least 45% below 1990 emission levels by 2035 and at least 80% below 1990 emission levels by 2050;

- Directed state agencies to integrate climate change and the State's GHG emissions reduction goals into their planning, budgets, investments, and decisions to the extent allowed by law;
- Directed the OPUC to—
    - determine whether utility portfolios and customer programs reduce risks and costs to utility customers by making rapid progress towards reducing GHG emissions consistent with Oregon's reduction goals;
    - encourage electric companies to support transportation electrification infrastructure that supports GHG emission reductions and zero emission vehicle goals; and
    - prioritize proceedings and activities that advance decarbonization in the utility sector and exercise its broad statutory authority to reduce GHG emissions, mitigate energy burden on utility customers, and ensure reliability and resource adequacy;
- Directed the Oregon Department of Environmental Quality to adopt a program to cap and reduce GHG emissions from large stationary sources, transportation fuels, and other liquid or gaseous fuels including natural gas; and
- More than doubled the reduction goals of the state's Clean Fuels Program and extended the program, from the previous rule that required a 10 percent reduction in average carbon intensity of fuels from 2015 levels by 2025, to a 25 percent reduction below 2015 levels by 2035.

*The Resource Planning Process*—PGE's planning process includes working with customers, stakeholders, and regulators to chart the course toward a clean, affordable, and reliable energy future. This process includes consideration of customer expectations and legislative mandates to move away from fossil fuel generation and toward renewable sources of energy.

In May 2018, the Company issued a request for proposals seeking to procure approximately 100 MWa of qualifying renewable resources. The prevailing bid was Wheatridge, an energy facility in eastern Oregon that will combine 300 MW of wind generation and 50 MW of solar generation with 30 MW of battery storage.

PGE now owns 100 MW of the wind resource, which was placed into service in the fourth quarter of 2020 at a cost of $149 million and qualified for PTCs at the 100 percent level. Subsidiaries of NextEra Energy Resources, LLC own the balance of the 300 MW wind resource, along with the solar and battery components, and will sell their portion of the output to PGE under 30-year power purchase agreements. PGE has the option to increase its ownership to include the entire facility in 2032.

Construction of the solar and battery components is planned for 2021 and is also expected to qualify for federal investment tax credits. PGE did not experience any supply chain disruptions due to the COVID-19 pandemic related to the construction of Wheatridge, and the solar and battery portions of the project are proceeding as planned. PGE continues to work closely with the contractor to actively monitor for supply chain issues. See "COVID-19 Impacts" within this Overview section for further information on COVID-19.

On May 6, 2020, the OPUC issued an order that acknowledged the Company's 2019 IRP and the following Action Plan for PGE to undertake over the next four years to acquire the resources identified:

- Customer actions—
    - Seek to acquire all cost-effective energy efficiency; and
    - Seek to acquire all cost-effective and reasonable distributed flexibility.
- Renewable actions—Conduct a Renewables Request for Proposals (RFP) seeking up to approximately 150 MWa of new RPS-eligible resources that contribute to meeting PGE's capacity needs by the end of 2024, with the following conditions, among others:
    - Resources must qualify for PTC or the federal Investment Tax Credit;

- Resources must pass the cost-containment screen; and
- The value of RECs generated prior to 2030 must be returned to customers.

- Capacity actions—Pursue dispatchable capacity through the following concurrent processes:
  - Pursue cost-competitive, bilateral contract agreements for existing capacity in the region; and
  - Conduct an RFP for non-emitting dispatchable resources that contribute to meeting PGE's capacity needs.

The order also requires that PGE consider resources in the Renewable and Capacity RFPs in a co-optimized manner. PGE had requested authorization to pursue up to approximately 700 MW of capacity contribution by 2025 from a combination of renewables, existing resources, and new non-emitting dispatchable capacity resources, such as energy storage. As PGE implements the Action Plan, the Company will continue to evaluate present and ongoing resource needs and timing of any related RFP in light of the economic disruption related to COVID-19. PGE expects to issue an RFP for both renewable energy and capacity resources.

PGE and Douglas County Public Utility District entered an agreement during 2020 to supply the Company additional capacity from facilities including the Wells Hydroelectric Project, located on the Columbia River in central Washington. The agreement also provides Douglas County PUD with PGE load management and wholesale market sales services. With a start date of January 1, 2021, the five-year agreement is expected to contribute between 100 and 160 MWs toward a capacity need that PGE identified in its 2019 IRP. The agreement is a further step toward the Company's stated goal of providing customers with a clean energy future.

PGE filed an IRP Update with the OPUC in January 2021 seeking acknowledgement so that it may incorporate the updated resource cost and value information in PURPA QF avoided cost pricing. No changes were proposed to the 2019 IRP Action Plan in the IRP Update. However, based on the updated capacity need forecast reflecting the addition of the agreement with the Douglas County PUD and more sophisticated modeling, the updated capacity need in 2025 is 511 MW.

*Renewable Recovery Framework*—As previously authorized by the OPUC, the RAC allows PGE to recover prudently incurred costs of renewable resources through filings made by April 1st each year. In the 2019 GRC Order, the OPUC authorized the inclusion of prudent costs of energy storage projects associated with renewables in future RAC filings to be made to the OPUC, under certain conditions. Although no significant filings were made under the RAC during 2020, the Company did submit a RAC filing for Wheatridge in the fourth quarter of 2019. On September 29, 2020, the OPUC issued an order in response to PGE's RAC filing that stated PGE's decision to proceed with Wheatridge was prudent and authorized cost recovery of, and return on, the facility in customer prices once service to PGE's customers began, in the fourth quarter 2020.

**Electrify other sectors of the economy**—PGE is working toward an equitable, safe, and clean energy future. Recent and future enhancements to the grid to enable a seamless platform include:

- The use of electricity in more applications such as electric vehicles and heat pumps;
- The integration of new, geographically-diverse energy markets;
- The deployment of new technologies like energy storage, communications networks, automation and control systems for flexible loads, and distributed generation;
- The development of connected neighborhood microgrids and smart communities; and
- The use of data and analytics to better predict demand and support energy saving customer programs.

In July 2019, PGE's Board approved plans to construct an Integrated Operations Center (IOC) as a key step to supporting this strategy, at an estimated total cost of $200 million, excluding AFDC. The IOC will centralize mission-critical operations, including those that are planned as part of the integrated grid strategy. This secure, resilient facility will include infrastructure to support and enhance grid operations and co-locate primary support functions. As of December 31, 2020, the Company has recorded $109 million, including AFDC, in construction work-in-progress related to the IOC.

The Company is also working to advance transportation electrification, with projects aimed at improving accessibility to electric vehicle charging stations and partnering with local mass transit agencies to transition to a greater use of electric vehicles. In June 2019, the Oregon Legislature enacted SB 1044, which establishes Oregon's zero emissions vehicle goals in statute at 250 thousand vehicle sales by 2025 and 90% of all vehicle sales by 2035. In September 2019, PGE filed with the OPUC its first Transportation Electrification plan, which considers current and planned activities, along with both existing and potential system impacts, in relation to the State’s carbon reduction goals.

In 2018, PGE filed an energy storage proposal that called for 39 MW of storage to be developed over the next several years at various locations across the grid. In August 2018, the OPUC issued an order that outlined an agreed approach to the development of five energy storage projects by PGE with an expected capital cost of approximately $45 million.

**Perform as a business**—PGE focuses on providing reliable, clean power to customers at affordable prices while providing a fair return to investors. To achieve this goal the Company must execute effectively within its regulatory framework and maintain prudent management of key financial, regulatory, and environmental matters that may affect customer prices and investor returns. The following discussion provides detail on several such material matters.

*Wildfire*—In 2020, Oregon experienced one of the most destructive wildfire seasons on record, with over one million acres of land burned. PGE’s wildfire mitigation planning includes regular risk assessment. On September 7, 2020 PGE proactively initiated a public safety power shutoff (PSPS) in a zone near Mt. Hood that was identified as the region at highest risk of wildfire. In addition to the PSPS region, PGE cut power to eight different high-risk fire areas. These actions were coordinated with emergency responders and helped clear the path for them to fight wildfires. During this time, PGE also established a community resource center within the PSPS zone to help support the residents affected. The Oregon Department of Forestry has opened an investigation into the causes of wildfires in Clackamas County. The Company has received a subpoena and is fully cooperating. The Company is not aware of any wildfires caused by PGE equipment. PGE will incur costs to replace and rebuild PGE facilities damaged by the fires, as well as addressing fire-damaged vegetation and other resulting debris and hazards both in and outside of PGE’s property and right-of-way. On October 20, 2020, the OPUC formally approved PGE’s request for deferral of such costs. As of December 31, 2020, PGE deferred $15 million in costs related to wildfire response. PGE continues to assess the damage to its infrastructure and expects regulatory recovery of prudently incurred restoration costs. Although PGE expects its 2020 regulated ROE, after adjusting for certain energy trading losses, to exceed its authorized ROE of 9.5%, PGE believes the full amount of the 2020 deferral is probable of recovery as the Company’s prudently incurred costs were in response to the unique and unprecedented nature of the wildfire events leading to the deferral. The OPUC has significant discretion in making the final determination of recovery and their conclusion of overall prudence, including an earnings review, could result in a portion, or all, of PGE’s 2020 deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

*Power Costs*—Pursuant to the AUT process, PGE annually files an estimate of power costs for the following year. As approved by the OPUC, the 2020 AUT included a final increase in power costs for 2020, and a corresponding increase in annual revenue requirement, of $27 million from 2019 levels, which were reflected in customer prices effective January 1, 2020. See “*Power Operations*” within this Overview section of Item 7 for more information regarding the PCAM.

*Portland Harbor Environmental Remediation Account (PHERA) Mechanism*—The EPA has listed PGE as one of over one hundred PRPs related to the remediation of the Portland Harbor Superfund site. As of December 31, 2020, significant uncertainties still remained 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. In a Record of Decision issued in 2017, the EPA outlined its selected remediation plan for clean-up of the Portland Harbor site, which had an estimated total cost of $1.7 billion. 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 PHERA mechanism. As approved by the OPUC, the Company's environmental recovery mechanism 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, and annual expenditures in excess of $6 million, excluding contingent liabilities, are subject to an annual earnings test. Under the PHERA mechanism in 2020, PGE incurred and deferred $6 million related to defense costs, net an estimated refund of less than $1 million as a result of the regulated earnings test. PGE's results of operations may be impacted to the extent such expenditures are deemed imprudent by the OPUC or disallowed per the prescribed earnings test. For further information regarding the PHERA mechanism, see "EPA Investigation of Portland Harbor" in Note 19, Contingencies in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

*City of Portland Audit*—In 2019, the city of Portland (the "City"), which is the largest city within PGE's service territory, completed its audit of PGE's and the City's mutual License Fees agreement for the 2012 through 2015 periods. The preliminary claim by the City is that PGE improperly excluded certain items from the calculation of gross revenues, which resulted in underpayment of franchise taxes of $7 million, including interest and penalties. PGE disagreed with the preliminary findings as they were not consistent with previous audit conclusions, which found that the Company had appropriately calculated gross revenues in determining franchise fees. In December 2020, PGE and the City reached a settlement for less than $1 million that covered the audit periods from 2012 to 2018.

*Capital Project Deferral*—In the second quarter of 2018, PGE placed into service a new customer information system at a total cost of $152 million. In accordance with agreements reached with stakeholders in the Company's 2019 GRC, the Company's capital cost of the asset was included in rate base and customer prices as of January 1, 2019.

Consistent with past regulatory precedent, in May 2018, the Company submitted an application to the OPUC to defer the revenue requirement associated with this new customer information system from the time the system went into service through the end of 2018. As a result, PGE began deferring its incurred expenses, primarily related to depreciation and amortization, of the new customer information system once it was placed in service.

In 2017, the OPUC had opened docket UM 1909 to conduct an investigation of the scope of its authority under Oregon law to allow the deferral of costs related to capital investments for later inclusion in customer prices. In October 2018, the OPUC issued Order 18-423 (1909 Order) concluding that the OPUC lacked authority under Oregon law to allow deferrals of any costs related to capital investments. In the 1909 Order, the OPUC acknowledged that this decision was contrary to its past limited practice of allowing deferrals related to capital investments and would require adjustments to its regulatory practices. The OPUC directed its Staff to meet with the utilities and stakeholders to address the full implications of this decision, and to propose recommendations needed to implement this decision consistent with the OPUC's legal authority and the public interest.

During 2018, PGE deferred a total of $12 million of expenses related to the customer information system. However, the 1909 Order impacted the probability of recovery of deferred expenses and, as such, the Company recorded a reserve for the full amount of the costs related to the customer information system. The reserve was established with an offsetting charge to the results of operations in 2018.

In response to the 1909 Order, PGE and other utilities filed a motion for reconsideration and clarification, which was denied. On April 19, 2019, PGE and the other utilities filed a petition for judicial review of the 1909 Order with the Oregon Court of Appeals, although the Court has indicated that the case would be dismissed given the lack of recent action in the case.

On April 30, 2020, the OPUC issued a final order affirming its authority to defer all cost components related to a utility's capital projects, including both depreciation expense and the cost of financing capital projects. PGE believes that the costs incurred to date associated with the customer information system were prudently incurred; however, PGE intends to file to close the deferral proceeding related to the customer information system without further action at the OPUC.

*Decoupling*—The decoupling mechanism, authorized by the OPUC through 2022, is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency, customer-owned generation, and conservation efforts by residential and certain commercial customers. The mechanism provides for collection from (or refund to) customers if weather-adjusted use per customer is less (or more) than that projected in the Company's most recent general rate case.

The Company recorded an estimated refund of $15 million and a collection of $9 million from residential and commercial customers, respectively for the year ended December 31, 2020, which resulted from variances between actual weather-adjusted use per customer and that projected in the 2019 GRC. The Company continues to see higher weather-adjusted use per customer from residential customers that are spending more time at home and lower use per customer from commercial customers that are adversely affected by COVID-19.

Collections under the decoupling mechanism are subject to an annual limitation of 2% of revenues for each eligible customer class, based on the net prices in effect for the applicable tariff schedule at the time of collection. For collections recorded in 2020, the 2% limit will be applied to the net prices for the applicable tariff schedules that will be in effect on January 1, 2022. The Company reached its 2020 annual cap for collection from commercial customers during the third quarter of 2020. No cap exists for any potential refunds under the decoupling mechanism, thus increased demand from residential customers since the onset of the COVID-19 pandemic has resulted in larger estimated refunds under the decoupling mechanism, which have largely offset the revenue increases that have resulted from higher residential demand. Any collection from customers for the 2020 year is expected to occur over a one-year period, which would begin January 1, 2022.

At December 31, 2019, PGE had recorded a total collection of $14 million that will be collected over a one-year period, which began January 1, 2021.

*Corporate Activity Tax*—In 2019, the state of Oregon enacted HB 3427, which imposes a new gross receipts tax on companies with annual revenues in excess of $1 million and applies to tax years beginning on or after January 1, 2020. The tax applies to commercial activities sourced in Oregon, less a deduction for 35% of the greater of "cost inputs" or "labor costs." The resulting amount is taxed at 0.57%.

In January 2020, at PGE's request, the OPUC issued an order approving a tariff and related deferral and balancing account to provide for an estimated recovery of $7 million in customer prices in 2020. The Company will revisit the expected tax consequences annually and revise the annual tariff accordingly. Pursuant to the order, PGE started collections in customer prices February 1, 2020. For the year ended December 31, 2020, PGE incurred $8 million under the tax.

*Non-utility Asset Retirement Obligation (ARO)*—PGE's Non-utility ARO represents the liability that has been recognized for portions of unregulated properties that are currently or previously leased to third parties and located adjacent to PGE's T.W. Sullivan hydro generating facility. In 2020, PGE performed a decommissioning study to update its ARO liability which resulted in a $21 million increase to non-utility property AROs. Additions in non-utility AROs related to assets that are no longer in service are charged directly to Depreciation and amortization on the consolidated statements of income in the period in which the revisions are probable and reasonably estimable. As a part of this study, the Company also established an additional ARO liability of $3 million related to utility properties that was charged to Depreciation and amortization expense. PGE plans to pursue regulatory recovery for the utility portion of the ARO update, however, as of December 31, 2020, no amounts have been deferred as a regulatory asset. For further information regarding the Company's AROs, see Note 8, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

*Deferral of Boardman Revenue Requirement*—In October 2020, intervenors filed a deferral application with the OPUC that would require PGE to defer and refund the revenue requirement associated with Boardman currently included in customer prices as established in the Company's last general rate case. The application states a deferral is required for customers to adequately capture the reduction in revenue requirement beginning on October 15, 2020, the date Boardman ceased operations. PGE estimates this amount could be up to $14 million for the period ended December 31, 2020. As of December 31, 2020, PGE has not recorded a regulatory liability pursuant to this deferral application as the Company believes its current prices are just and reasonable in light of PGE's continued substantial investments in utility plant. The costs of these investments, which are not currently reflected in customer prices, more than offsets the revenue requirement for Boardman. If the OPUC authorizes the deferral, PGE would record a regulatory liability with a corresponding charge to earnings.

*2021 Storm*— Beginning on February 11, 2021, an historic set of storms involving heavy snow, winds, and ice impacted the United States, including PGE's service territory. Significant damage across the State of Oregon led Oregon's Governor to call a state of emergency on February 13, 2021. PGE's restoration efforts in response to this historic set of storms are ongoing and the total costs of the storm cannot be reasonably estimated, although such costs could be material to its results of operations in 2021. Given the magnitude of the impacts to PGE's transmission and distribution system, on February 15, 2021 PGE filed a deferral application with the OPUC for potential recovery of restoration costs, however, there is no assurance that such recovery would be granted by the OPUC.

**Operating Activities**

In combination with electricity provided by its own generation portfolio, to meet its retail load requirements and balance its energy supply with customer demand, PGE purchases and sells electricity in the wholesale market. PGE also participates in the CAISO western EIM, which allows the Company to, among other things, integrate more renewable energy into the grid by better matching the variable output of renewable resources. PGE also purchases natural gas in the United States and Canada to fuel its generation portfolio and sells excess gas back into the wholesale market.

The Company generates revenues and cash flows primarily from the sale and distribution of electricity to its retail customers. The impact of seasonal weather conditions on demand for electricity can cause the Company's revenues, cash flows, and income from operations to fluctuate from period to period. Historically, PGE has experienced its highest MWa deliveries and retail energy sales during the winter heating season, although instances of peak deliveries have increased during the summer months, generally resulting from air conditioning demand. See *"Seasonality"* in the Customers and Revenues section in Item 1.—"Business." for further information regarding seasonal fluctuations. Retail customer price changes and customer usage patterns, which can be affected by the economy, also have an effect on revenues. Wholesale power availability and price, hydro and wind generation, and fuel costs for thermal and gas plants can also affect income from operations.

**Customers and Demand**—The following tables present total energy deliveries and the average number of retail customers by customer type for 2020 and 2019.

| Energy deliveries (MWh in thousands) | 2020 | 2019 | % Increase/ (Decrease) |
|---|---|---|---|
| Retail: | | | |
| Residential | 7,756 | 7,471 | 3.8 % |
| | | | |
| Commercial (PGE sales only) | 6,222 | 6,653 | (6.5) |
| Direct Access | 633 | 665 | (4.8) |
| Total Commercial | 6,855 | 7,318 | (6.3) |
| | | | |
| Industrial (PGE sales only) | 3,446 | 3,181 | 8.3 |
| Direct Access | 1,486 | 1,490 | (0.3) |
| Total Industrial | 4,932 | 4,671 | 5.6 |
| | | | |
| Total (PGE sales only) | 17,424 | 17,305 | 0.7 |
| Total Direct Access | 2,119 | 2,155 | (1.7) |
| Total retail energy deliveries | 19,543 | 19,460 | 0.4 % |
| Wholesale energy deliveries | 5,794 | 4,669 | 24.1 |
| Total energy deliveries | 25,337 | 24,129 | 5.0 % |

| Average number of retail customers | 2020 | | 2019 | | % Increase |
|---|---|---|---|---|---|
| Residential | 791,119 | 88 % | 779,673 | 88 % | 1.5 % |
| Commercial | 110,290 | 12 | 109,521 | 12 | 0.7 |
| Industrial | 194 | — | 193 | — | 0.5 |
| Direct access | 634 | — | 632 | — | 0.3 |
| Total | 902,237 | 100 % | 890,019 | 100 % | 1.4 % |

In 2020, retail energy deliveries increased 0.4% from 2019. While results for the first quarter largely reflected conditions prior to the COVID-19 pandemic, the remainder of the year was influenced by customer behavioral response to the pandemic.

On March 23, 2020, the Governor of Oregon issued an order directing residents to stay at home except for essential activity and mandating closure of businesses for which close personal contact would be difficult or impossible to avoid. The Company saw a shift in retail demand in response, beginning with the second quarter of 2020. In particular, residential loads increased as a larger percentage of the population spent more time at home, whether working from home, providing child-care due to school closures, or lacking employment as commercial activity slowed. Conversely, commercial energy deliveries declined as many businesses were disrupted in an attempt to maintain social distancing or have closed as a result of the lack of business as residents followed directives from state and federal authorities. Although the industrial class as a whole experienced an increase in energy deliveries for 2020, this was due primarily to continued growth in the high-tech and digital services sectors, which saw lesser impacts from noted closures than other sectors.

Residential energy deliveries, which are most sensitive to fluctuations in temperatures, were 3.8% higher in 2020 than 2019, due to a 2.3% increase in average usage per customer and a 1.5% increase in the average number of customers. Residential deliveries, down 6% in the first quarter driven by mild temperatures, were up 9% in the second quarter of 2020 due largely to the impact of the COVID-19 pandemic and have remained strong through the balance of the year.

Commercial energy deliveries declined 6.3% overall with widespread decreases across PGE's customer base led by several sectors most impacted by COVID-19 related closures and economic conditions, including: government and education; offices, finance, insurance, and real estate; and restaurants and lodging.

The 5.6% increase during 2020 in industrial energy deliveries is due to continued strength in the high-tech manufacturing sector as well as a full-year of demand from a large paper facility that reopened during 2019, after having closed in late 2017.

In 2020, the Company's service territory experienced warmer temperatures during the heating season than in 2019, indicating lower demand for heating, the effect of which was partially offset by having slightly warmer temperatures during the summer cooling season and increased demand for cooling.

Total heating degree-days, an indication of electricity use for heating, in 2020 were 7% below the 15-year average and down 8% from total heating degree-days in 2019. Total cooling degree-days, a similar indication of the extent to which customers are likely to have used electricity for cooling, in 2020, exceeded the 15-year average by 12% and were 6% above the 2019 total. The following table presents the number of heating and cooling degree-days in 2020 and 2019, along with the current 15-year averages, reflecting that weather had a considerable influence on comparative energy deliveries:

| | **Heating Degree-Days** | | | **Cooling Degree-Days** | | |
|---|---|---|---|---|---|---|
| | **2020** | **2019** | **15-Year Average** | **2020** | **2019** | **15-Year Average** |
| 1st quarter | 1,761 | 1,992 | 1,848 | — | — | — |
| 2nd quarter | 554 | 467 | 636 | 99 | 102 | 89 |
| 3rd quarter | 47 | 83 | 78 | 492 | 462 | 447 |
| 4th quarter | 1,474 | 1,623 | 1,583 | 9 | — | 2 |
| Total | 3,836 | 4,165 | 4,145 | 600 | 564 | 538 |
| Increase (decrease) from the 15-year average | (7)% | — % | | 12 % | 5 % | |

On a weather-adjusted basis, total retail deliveries increased 1.5% from 2019. The increase was driven by 6.3% growth in residential deliveries and 5.6% growth in industrial energy deliveries, which were somewhat offset by a decrease in commercial energy deliveries of 6.0%. Retail energy deliveries for 2021 will continue to be impacted by COVID-19 related behavioral changes. PGE projects that retail energy deliveries for 2021 will be approximately

1.0% - 1.5% above 2020 weather-adjusted levels, reflecting strength in industrial deliveries, and impacts associated with COVID-19 early in the year, and unwinding of such impacts later in the year.

ESSs supplied Direct Access customers with energy representing 11% of the Company's total retail energy deliveries during 2020 and 2019. The maximum retail load allowed to be supplied under the fixed three-year and minimum five-year opt-out programs represent 13% of the Company's total retail energy deliveries for 2020, and 2019. With the adoption of the New Large Load Direct Access program in 2020, as much as 19% of the Company's energy deliveries could have been supplied by ESSs.

Energy efficiency and conservation efforts by retail customers influence demand, although the financial effects of such efforts by residential and certain commercial customers are mitigated by the decoupling mechanism, which is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts. The mechanism provides for collection from (or refund to) customers if weather-adjusted use per customer is less (or more) than the projected baseline set in the Company's most recent approved general rate case. See *"Decoupling"* in this Overview section of Item 7, for further information on the decoupling mechanism.

*Power Operations*—PGE utilizes a combination of its own generating resources and wholesale market transactions to meet the energy needs of its retail customers. Based on numerous factors, including plant availability, customer demand, river flows, wind conditions, and current wholesale prices, the Company continuously makes economic dispatch decisions in an effort to obtain reasonably-priced power for its retail customers. PGE also purchases wholesale natural gas in the United States and Canada to fuel its generating portfolio and sells excess gas back into the wholesale market. As a result, the amount of power generated and purchased in the wholesale market to meet the Company's retail load requirement can vary from period to period and impacts NVPC and income from operations.

The following table provides information regarding the performance of the Company's generation portfolio.

| | **Plant availability (1)** | | **Actual energy provided compared to projected levels (2)** | | **Actual energy provided as a percentage of total retail load** | |
|---|---|---|---|---|---|---|
| | **2020** | **2019** | **2020** | **2019** | **2020** | **2019** |
| Thermal: | | | | | | |
| Natural gas | 92 % | 92 % | 74 % | 86 % | 43 % | 45 % |
| Coal (3) | 99 | 87 | 83 | 104 | 17 | 24 |
| Wind | 94 | 96 | 117 | 90 | 11 | 9 |
| Hydro | 86 | 93 | 71 | 81 | 7 | 8 |

(1) Plant availability represents the percentage of the year plants were available for operations, which is impacted by planned maintenance and forced, or unplanned, outages.
(2) Projected levels of energy are included as part of PGE's AUT. Such projections establish the power cost component of retail prices for the following calendar year. Any shortfall is generally replaced with power from higher cost sources, while any excess generally displaces power from higher cost sources.
(3) Plant availability excludes Colstrip, which PGE does not operate. Colstrip availability was 74% in 2020, compared with 85% in 2019. Boardman ceased coal-fired generation on October 15, 2020.

Energy received from PGE-owned and jointly-owned thermal plants decreased 12% in 2020 compared to 2019, primarily as a result of a 27% reduction in generation from coal-fired generation, which produced only 13% of the Company's total system load in 2020. Energy expected to be received from thermal resources is projected annually in the AUT based on forecast market prices, variable costs to run the plant, and the constraints of the plant. PGE's thermal generating plants require varying levels of annual maintenance, which is generally performed during the second quarter of the year.

Total energy received from hydroelectric generation sources, both PGE-owned generation and purchased, increased 12% in 2020 compared to 2019. While energy received from mid-Columbia hydroelectric projects increased 46% in 2020, the energy generated by the Company-owned facilities decreased 14%. Energy expected to be received from hydroelectric resources is projected annually in the AUT based on a modified hydro study, which utilizes 80 years of historical stream flow data. See *"Purchased power and fuel"* in the Results of Operations section in this Item 7, for further detail on regional hydro results.

Energy received from PGE-owned wind resources and under contracts increased 28% in 2020 compared to 2019, due to more favorable wind conditions in 2020 and the addition of Wheatridge during the fourth quarter 2020. Energy expected to be received from Biglow Canyon and Tucannon River is projected annually in the AUT based on historical generation. Wind generation forecasts are developed using a 5-year rolling average of historical wind levels or forecast studies when historical data is not available. As a result of the generation increase, a larger amount of PTCs were produced in 2020 than in 2019 and exceeded what was contemplated in the Company's prices.

For Wheatridge, wind generation studies were used to develop NVPC cost forecasts, which were included in the RAC filing for the facility, and included in customer prices when the facility went into service. The RAC tariff included NVPC in 2020 along with all other aspects of the revenue requirement. Beginning January 1, 2021, the NVPCs were included in the Company's AUT, although the other aspects of the RAC tariff will remain in effect until they are included in customer prices as a result of a future general rate case.

Under the PCAM, PGE may share with customers a portion of cost variances associated with NVPC. Customer prices can be adjusted annually to absorb a portion of the difference between the forecasted NVPC included in customer prices (baseline NVPC) and actual NVPC for the year, if such differences exceed a prescribed "deadband" limit, 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. The following is a summary of the results of the Company's PCAM as calculated for regulatory purposes for 2020, and 2019:

- For 2020, actual NVPC, excluding certain trading losses totaling $127 million, was below baseline NVPC by $13 million, which was within the established deadband range, so no estimated refund to customers was recorded as of December 31, 2020. A final determination regarding the 2020 PCAM results will be made by the OPUC through a public filing and review in 2021. If actual NVPC for 2020 included the certain trading losses, it would have been $114 million above the baseline. See "Energy Trading" in the Overview section of this Item 7. for further information regarding certain trading losses.
- For 2019, actual NVPC was above baseline NVPC by $5 million, which was within the established deadband range. Accordingly, no estimated refund to customers was recorded as of December 31, 2019. A final determination regarding the 2019 PCAM results was made by the OPUC through a public filing and review in 2020, which confirmed no refund to customers pursuant to the PCAM for 2019.

The AUT filing, which serves to reset the baseline NVPC for PCAM purposes, indicated that a $27 million increase was expected in 2020 over 2019. The 2021 AUT anticipates a $79 million increase in NVPCs that will be recovered in customer prices beginning January 1, 2021.

**Results of Operations**

The following tables provide financial and operational information to be considered in conjunction with management's discussion and analysis of results of operations.

PGE defines Gross margin as Total revenues less Purchased power and fuel. Gross margin is considered a non-GAAP measure as it excludes depreciation and amortization and other operation and maintenance expenses. The presentation of Gross margin is intended to supplement an understanding of PGE's operating performance in relation to changes in customer prices, fuel costs, impacts of weather, customer counts and usage patterns, and impact from regulatory mechanisms such as decoupling. The Company's definition of Gross margin may be different from similar terms used by other companies and may not be comparable to their measures.

The results of operations are as follows for the years presented (dollars in millions):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | % Increase (Decrease) |
| | Amount | Amount | |
| **Total revenues** [(1)] | $ 2,145 | $ 2,123 | 1 % |
| Purchased power and fuel [(1)] | 708 | 614 | 15 |
| **Gross margin** | 1,437 | 1,509 | (5) |
| **Other operating expenses:** | | | |
| Generation, transmission and distribution | 293 | 323 | (9) |
| Administrative and other | 283 | 290 | (2) |
| Depreciation and amortization | 454 | 409 | 11 |
| Taxes other than income taxes | 138 | 134 | 3 |
| Total other operating expenses | 1,168 | 1,156 | 1 |
| Income from operations | 269 | 353 | (24) |
| **Interest expense, net** [(2)] | 136 | 128 | 6 |
| **Other income:** | | | |
| Allowance for equity funds used during construction | 16 | 10 | 60 |
| Miscellaneous income, net | 6 | 6 | — |
| **Other income, net** | 22 | 16 | 38 |
| Income before income taxes | 155 | 241 | (36) |
| **Income tax (benefit) expense** | — | 27 | (100) |
| **Net income** | $ 155 | $ 214 | (28)% |

(1) Gross margin agrees to Total revenues less Purchased power and fuel as reported on PGE's Consolidated Statements of Income.

(2) Includes an allowance for borrowed funds used during construction of $8 million in 2020 and $5 million in 2019.

*2020 Compared to 2019*

**Net income** - The following items contributed to the change in Net income for the year ended December 31, 2020 compared to the year ended December 31, 2019 (dollars in millions):

| | | |
|---|---|---|
| Year ended December 31, 2019 | $ | 214 |
| Purchased power and fuel expense related to certain trading losses* | | (127) |
| Purchased power and fuel expense, excluding certain trading losses* | | 43 |
| Other operating revenues primarily from the resale of excess natural gas used for fuel in 2019 that did not recur in 2020 | | (17) |
| Average retail price predominately due to increase under the AUT for NVPC | | 37 |
| Retail deliveries, net of decoupling deferral | | (11) |
| Wholesale revenues driven by lower average sale prices | | (8) |
| Late fee revenue due largely to COVID-19 related curtailments | | (6) |
| Generation, transmission and distribution expenses driven by lower plant maintenance | | 30 |
| Administrative and general expenses due largely to lower wages and benefits | | 9 |
| Non-utility ARO due to revised estimates | | (21) |
| Depreciation and amortization resulting largely from capital additions | | (11) |
| Income taxes resulting primarily from lower pre-tax income | | 27 |
| Other | | (4) |
| Year ended December 31, 2020 | | 155 |
| Change in Net income | $ | (59) |

*See "Energy Trading" in the Overview section of this Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations" for further information regarding certain trading losses.

**Total revenues** consist of the following for the years presented (in millions):

| | 2020 | 2019 | % Increase (Decrease) |
|---|---|---|---|
| Retail: (1) | | | |
| Residential | $ 1,030 | $ 981 | 5 % |
| Commercial | 616 | 636 | (3) |
| Industrial | 218 | 196 | 11 |
| Direct Access | 46 | 44 | 5 |
| Subtotal | 1,910 | 1,857 | 3 |
| Alternative revenue programs, net of amortization | (6) | 2 | (400) |
| Other accrued revenues, net (2) | 28 | 22 | 27 |
| Total retail revenues | 1,932 | 1,881 | 3 |
| Wholesale revenues | 162 | 170 | (5) |
| Other operating revenues | 51 | 72 | (29) |
| Total revenues | $ 2,145 | $ 2,123 | 1 % |

(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those customers that purchase their energy from ESSs. Commercial revenues from ESS customers were $18 million for 2020 and 2019. Industrial revenues from ESS customers were $28 million and $26 million for 2020 and 2019, respectively.

(2) Amounts for the years ended December 31, 2020 and 2019 are primarily comprised of $24 million and $23 million of amortization, respectively, including interest, related to the net tax benefits due to the change in corporate tax rate under the TCJA.

*Total retail revenues*—The following items contributed to the increase in Total retail revenues for the year ended December 31, 2020 compared to the year ended December 31, 2019 (dollars in millions):

| | | |
|---|---|---|
| Year ended December 31, 2019 | $ | 1,881 |
| Retail energy deliveries driven by higher industrial demand, the impact of COVID-19 resulting in higher residential demand, and the negative effects of weather | | 8 |
| Average price of energy deliveries due primarily to the AUT and the variation in usage among customer classes resulting from COVID-19 | | 27 |
| Combination of various supplemental tariffs and adjustments, the largest of which were $11 million that pertains to the demand response pilot programs, $8 million related to Boardman decommissioning, and $7 million for the Oregon Commercial Activities Tax | | 24 |
| Alternative revenue programs related to the decoupling mechanism deferrals due to increased residential use per customer resulting from COVID-19 | | (19) |
| Amortization of prior year decoupling deferrals into customer prices | | 11 |
| Year ended December 31, 2020 | | 1,932 |
| Change in Total retail revenues | $ | 51 |

*Wholesale revenues* result from sales of electricity to utilities and power marketers made in the Company's efforts to secure reasonably priced power for its retail customers, manage risk, and administer its current long-term wholesale contracts. Such sales can vary significantly from year to year as a result of economic conditions, power and fuel prices, hydro and wind availability, and customer demand.

In 2020, an $8 million, or 5%, decrease from 2019 in wholesale revenues resulted from a $49 million decrease from a 23% decrease in average prices received when the Company sold power into the wholesale market, partially offset by a $41 million increase related to a 24% increase in wholesale sales volume.

*Other operating revenues* decreased $21 million, or 29%, in 2020 from 2019, primarily as a result of a $17 million decrease predominately resulting from market conditions that provided less revenue from the resale of natural gas back into the wholesale market in excess of amounts needed for the Company's generation portfolio. Natural gas prices were considerably higher in the first quarter of 2019 as a result of a supply pipeline disruption in the region. Milder than average winter temperatures in North America in 2020 resulted in an oversupply of natural gas and lower prices. In addition, a $6 million decrease occurred due to the curtailment of late fees as a result of the COVID-19 pandemic.

**Purchased power and fuel** expense includes 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.

The following items contributed to the increase in Purchased power and fuel for the year ended December 31, 2020 compared to the year ended December 31, 2019 (dollars in millions, except for average variable power cost per MWh):

| | | |
|---|---|---|
| Year ended December 31, 2019 | $ | 614 |
| Average variable power cost per MWh | | 62 |
| Total system load | | 32 |
| Year ended December 31, 2020 | $ | 708 |
| Change in Purchased power and fuel | $ | 94 |

| | | |
|---|---|---|
| Average variable power cost per MWh: | | |
| Year ended December 31, 2019 | $ | 26.62 |
| Year ended December 31, 2020 | $ | 29.14 |

| | |
|---|---|
| Total system load (MWh in thousands): | |
| Year ended December 31, 2019 | 23,085 |
| Year ended December 31, 2020 | 24,286 |

For the year ended December 31, 2020, the $62 million increase related to the change in average variable power cost per MWh, was primarily driven by an 8% increase in the average cost for purchased power, partially offset by a 14% decrease on the average cost for the Company's own generation. The increase in the cost of purchased power was driven by realized losses of $127 million related to a portion of energy trading positions in PGE's energy portfolio. See *"Energy Trading"* in the Overview section of this Item 7., for more details. The $32 million increase related to total system load was primarily due to a 35% increase in purchased power, driven by economic dispatch decisions based on lower gas prices and surplus hydro in the region.

PGE's sources of energy, total system load, and retail load requirement for the years presented are as follows:

| | **Years Ended December 31,** | | | |
|---|---|---|---|---|
| | **2020** | | **2019** | |
| **Sources of energy (MWh in thousands):** | | | | |
| Generation: | | | | |
| Thermal: | | | | |
| Natural gas | 8,029 | 33 % | 8,342 | 36 % |
| Coal | 3,232 | 13 | 4,416 | 19 |
| Total thermal | 11,261 | 46 | 12,758 | 55 |
| Hydro | 1,204 | 5 | 1,407 | 6 |
| Wind | 2,111 | 9 | 1,706 | 8 |
| Total generation | 14,576 | 60 | 15,871 | 69 |
| Purchased power: | | | | |
| Term contracts | 7,741 | 32 | 5,882 | 25 |
| Hydro | 1,535 | 6 | 1,048 | 5 |
| Wind | 434 | 2 | 284 | 1 |
| Total purchased power | 9,710 | 40 | 7,214 | 31 |
| Total system load | 24,286 | 100 % | 23,085 | 100 % |
| Less: wholesale sales | (5,794) | | (4,669) | |
| Retail load requirement | 18,492 | | 18,416 | |

The following table presents the actual April-to-September 2020 and 2019 runoff at particular points of major rivers relevant to PGE's hydro resources:

| | Runoff as a Percent of 30-year Average | |
|---|---|---|
| Location | 2020 Actual | 2019 Actual |
| Columbia River at The Dalles, Oregon | 104 % | 94 % |
| Mid-Columbia River at Grand Coulee, Washington | 109 | 87 |
| Clackamas River at Estacada, Oregon | 75 | 114 |
| Deschutes River at Moody, Oregon | 86 | 111 |

**Actual NVPC**, which consists of Purchased power and fuel expense net of Wholesale revenues, increased $102 million in 2020 compared with 2019. The increase attributable to changes in Purchased power and fuel expense was the result of a 9% increase in the average variable power cost per MWh and a 5% increase in total system load. In addition, wholesale energy deliveries decreased $8 million from the net of 23% lower average price per MWh sold, partially offset by a 24% increase in the volume of wholesale energy deliveries.

The following items contributed to the increase in Actual NVPC for the year ended December 31, 2020 compared to the year ended December 31, 2019 (in millions):

| | | |
|---|---|---|
| Year ended December 31, 2019 | $ | 444 |
| Purchased power and fuel expense | | 94 |
| Wholesale revenues | | 8 |
| Year ended December 31, 2020 | | 546 |
| Change in NVPC | $ | 102 |

For further information regarding NVPC in relation to the PCAM, see *"Power Operations"* in the Overview section of this Item 7.

**Generation, transmission, and distribution**

The following items contributed to the $30 million or 9% decrease in Generation, transmission and distribution for the year ended December 31, 2020 compared to the year ended December 31, 2019 (in millions):

| | | |
|---|---|---|
| Year ended December 31, 2019 | $ | 323 |
| Decrease primarily due to lower maintenance expense as the result of reduced run hours and lower long-term service agreement costs at some of the Company's generation facilities | | (20) |
| Lower utilization of contract labor and higher capitalization rates | | (8) |
| Miscellaneous expenses | | (2) |
| Year ended December 31, 2020 | | 293 |
| Change in Generation, transmission and distribution | $ | (30) |

For the year ended December 31, 2020, PGE deferred $15 million of incremental costs related to wildfires in PGE's service territory. See *"Wildfires"* within "Perform as a business" under "Company Strategy" in the Overview section of this Item 7., for more information.

**Administrative and other**

The following items contributed to the $7 million or 2% decrease in Administrative and other for the year ended December 31, 2020 compared to the year ended December 31, 2019 (in millions):

| | | |
|---|---|---|
| Year ended December 31, 2019 | $ | 290 |
| Wage and benefits expenses | | (12) |
| Bad debt expense | | 5 |
| Year ended December 31, 2020 | | 283 |
| Change in Administrative and other | $ | (7) |

As of December 31, 2020, PGE has deferred $8 million of bad debt related to incremental expense incurred related to COVID-19 as part of the OPUC's Energy Term Sheet. See the "*Overview*" section of this Item 7., for more information.

**Depreciation and amortization**

The following items contributed to the $45 million or 11%, increase in Depreciation and amortization for the year ended December 31, 2020 compared to year ended December 31, 2019 (in millions):

| | | |
|---|---|---|
| Year ended December 31, 2019 | $ | 409 |
| ARO revisions | | 24 |
| Activity related to regulatory programs (offset in revenues) | | 13 |
| Capital additions | | 8 |
| Year ended December 31, 2020 | | 454 |
| Change in Depreciation and amortization | $ | 45 |

See *"Non-utility Asset Retirement Obligation Overview"* within "Perform as a business" under "Company Strategy" in the Overview section of this Item 7., for more information regarding revisions made to non-utility AROs.

**Taxes other than income taxes** expense increased $4 million, or 3%, in 2020 compared with 2019, primarily due to higher Oregon property taxes.

**Interest expense** increased $8 million, or 6%, in 2020 compared with 2019 due to higher average balances of outstanding debt as well as increased interest on finance leases.

**Other income, net** increased $6 million, or 38%, in 2020 compared to 2019, with the difference due to higher AFDC equity driven by higher construction work-in-progress balances in 2020.

**Income tax expense** decreased $27 million, or 100%, in 2020 compared to 2019 primarily due to lower pre-tax income in 2020, partially offset by higher expense from the Oregon Corporate Activity tax which took effect on January 1, 2020.

*2019 Compared to 2018*

For a comparison of the Company's results of operations for the fiscal year ended December 31, 2019 to the year ended December 31, 2018, see Item 7.—" Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Annual report on Form 10-K for the year ended December 31, 2019, filed with the SEC on February 14, 2020.

### *Liquidity and Capital Resources*

Discussions, forward-looking statements, and projections in this section, and similar statements in other parts of this Annual Report on Form 10-K, are subject to PGE's assumptions regarding the availability and cost of capital. See *"Capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan as currently envisioned."* in Item 1A.—"Risk Factors," for further information.

*Capital Requirements*

The following table presents actual capital expenditures and debt maturities for 2020 and projected capital expenditures and future debt maturities for 2021 through 2025 (in millions, excluding AFDC):

| | Years Ending December 31, | | | | | |
|---|---|---|---|---|---|---|
| | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** |
| Ongoing capital expenditures* | $ 568 | $ 555 | $ 550 | $ 550 | $ 550 | $ 550 |
| Integrated Operations Center | 77 | 100 | — | — | — | — |
| Wheatridge Renewable Energy Facility | 129 | — | — | — | — | — |
| Total capital expenditures | $ 774 | $ 655 | $ 550 | $ 550 | $ 550 | $ 550 |
| Long-term debt maturities | $ — | $ 160 | $ — | $ — | $ 80 | $ — |

* Consists primarily of upgrades to, and replacement of, generation, transmission, and distribution infrastructure, as well as new customer connects. Includes preliminary engineering and removal costs.

During 2020, PGE funded its capital expenditures through a combination of cash from operations in the amount of $567 million, net proceeds from the issuance of PCRBs and FMBs in the total amount of $451 million, and net short-term debt issuances in the amount of $150 million. Capital expenditures in 2021 are expected to be $655 million. PGE plans to fund the 2021 capital expenditures and long-term debt maturities with cash from operations during 2021, which is expected to range from $600 million to $650 million, the issuance of debt securities of up to $300 million, and the issuance of commercial paper, as needed. The actual timing and amount of any other issuances of debt or commercial paper will be dependent upon the timing and amount of capital expenditures. For a discussion concerning PGE's ability to fund its future capital requirements, see "*Debt and Equity Financings*" in the Liquidity and Capital Resources section of this Item 7.

*Liquidity*

PGE's access to short-term debt markets, including revolving credit from banks, helps provide necessary liquidity to support the Company's current operating activities, including the purchase of power and fuel. Long-term capital requirements are driven largely by capital expenditures for distribution, transmission, and generation facilities to support both new and existing customers, information technology systems, and debt refinancing activities. PGE's liquidity and capital requirements can also be significantly affected by other working capital needs, including margin deposit requirements related to wholesale market activities, which can vary depending upon the Company's forward positions and the corresponding price curves.

The following summarizes PGE's cash flows for the periods presented (in millions):

| | Years Ended December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Cash and cash equivalents, beginning of year | $ 30 | $ 119 |
| Net cash provided by (used in): | | |
| Operating activities | 567 | 546 |
| Investing activities | (787) | (604) |
| Financing activities | 447 | (31) |
| Net change in cash and cash equivalents | 227 | (89) |
| Cash and cash equivalents, end of year | $ 257 | $ 30 |

2020 Compared to 2019

*Cash Flows from Operating Activities*—Cash flows from operating activities are generally determined by the amount and timing of cash received from customers and payments made to vendors, as well as the nature and amount of non-cash items, including depreciation and amortization, deferred income taxes, and pension and other postretirement benefit costs included in net income during a given period. The $21 million increase in cash flows from operating activities in 2020 compared to 2019 is due to:

- $59 million reduction in Net income in 2020;
- $63 million increase related to additional contributions to the pension and other postretirement benefit plans in 2019 that did not recur in 2020;
- $45 million increase in Depreciation and amortization primarily due to higher average plant balances and revision to non-utility AROs in 2020. See the Overview section of this Item 7., for more information regarding revisions made to non-utility AROs;
- $42 million increase for Accounts payable and other accrued liabilities primarily due to the timing of payments to vendors;
- $29 million increase in Other working capital, net primarily due to the use of materials and supplies and fuel inventory in the course of business; partially offset by
- $54 million decrease as a result of changes in Accounts receivable and Unbilled revenue;
- $29 million decrease related to Deferred income taxes;
- $9 million decrease related to cash settlements for ARO liabilities; and
- $7 million decrease related to other miscellaneous items.

For additional information regarding changes in Net income, see the Results of Operations section in this Item 7.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. The Company estimates that such charges in 2021 will range from $410 million to $430 million. Combined with all other sources, cash provided by operations in 2021 is estimated to range from $600 million to $650 million.

*Cash Flows from Investing Activities*—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE's distribution, transmission, and generation facilities. The $183 million increase in net cash used in investing activities in 2020 compared with 2019 is primarily due to the construction of Wheatridge and the IOC.

The Company plans for $655 million of capital expenditures in 2021 related to upgrades to and replacement of generation, transmission, and distribution infrastructure. PGE plans to fund the 2021 capital expenditures with cash from operations during 2021, as discussed above, as well as with the issuance of short- and long-term debt securities. For additional information, see "*Capital Requirements*" and "*Debt and Equity Financings*" in the Liquidity and Capital Resources section of this Item 7.

*Cash Flows from Financing Activities*—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During 2020, cash provided by financing activities consisted primarily of the issuance of $430 million of FMBs and $119 million of PCRBs, less the remarketing of $98 million of PCRBs. In addition, the Company issued a $150 million short-term loan and paid dividends in the amount of $140 million.

2019 Compared to 2018

For a comparison of liquidity and capital resources and the Company's cash flow activities for the fiscal year ended December 31, 2019 and 2018, see Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Annual Report on Form 10-K for the year ended December 31, 2019, which was filed with the SEC on February 14, 2020.

***Credit Ratings and Debt Covenants***

PGE's secured and unsecured debt is rated investment grade by Moody's and S&P, with current credit ratings and outlook as follows:

| | Moody's | S&P |
|---|---|---|
| First Mortgage Bonds | A1 | A |
| Senior unsecured debt | A3 | BBB+ |
| Commercial paper | P-2 | A-2 |
| Outlook | Stable | Stable |

In the event Moody's and/or S&P reduce their credit rating on PGE's unsecured debt below investment grade, the Company could be subject to requests by certain of its wholesale, commodity, and transmission counterparties to post additional performance assurance collateral in connection with its price risk management activities. The performance assurance collateral can be in the form of cash deposits or letters of credit, depending on the terms of the underlying agreements, and are based on the contract terms and commodity prices and can vary from period to period. Cash deposits provided as collateral are classified as Margin deposits in PGE's consolidated balance sheets, while any letters of credit issued are not reflected in the Company's consolidated balance sheets.

As of December 31, 2020, PGE had posted $20 million of collateral with these counterparties, consisting of $8 million in cash and $12 million in bank letters of credit. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of December 31, 2020, the amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is $32 million and decreases to zero by December 31, 2021. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is $122 million and decreases to $79 million by December 31, 2021 and $72 million by December 31, 2022.

PGE's financing arrangements do not contain ratings triggers that would result in the acceleration of required interest and principal payments in the event of a ratings downgrade. However, the cost of borrowing and issuing letters of credit under the credit facilities would increase.

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. The issuance of FMBs requires that PGE meet earnings coverage and security provisions set forth in the Indenture of

Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2020, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to $695 million of additional FMBs. Any issuances of FMBs would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges, or other dispositions of property.

PGE's credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65.0% of total capitalization (debt to total capital ratio). As of December 31, 2020, the Company's debt to total capital ratio, as calculated under the credit agreements, was 56.4%.

***Debt and Equity Financings***

PGE's ability to secure sufficient short- and long-term capital at a reasonable cost is determined by its financial performance and outlook, its credit ratings, its capital expenditure requirements, alternatives available to investors, market conditions, and other factors, such as the significant volatility in the capital markets in response to COVID-19. Management believes that the availability of its revolving credit facility, the expected ability to issue short- and long-term debt and equity securities, and cash expected to be generated from operations provide sufficient cash flow and liquidity to meet the Company's anticipated capital and operating requirements for the foreseeable future.

*Short-term Debt*—Pursuant to an order issued by the FERC on January 16, 2020, PGE has authorization to issue short-term debt up to a total of $900 million through February 6, 2022. The following table shows available liquidity as of December 31, 2020 (in millions):

| | December 31, 2020 | | |
|---|---|---|---|
| | Capacity | Outstanding | Available |
| Revolving credit facility (1) | $ 500 | $ — | $ 500 |
| Letters of credit (2) | 220 | 60 | 160 |
| Total credit | $ 720 | $ 60 | $ 660 |
| Cash and cash equivalents | | | 257 |
| Total liquidity | | | $ 917 |

(1) Scheduled to expire November 2023.
(2) PGE has four letter of credit facilities under which the Company can request letters of credit for an original term not to exceed one year.

As of December 31, 2020, PGE had a $500 million revolving credit facility scheduled to expire in November 2023. The facility allows for unlimited extension requests, provided that lenders with a pro-rata share of more than 50% of the facility 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 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 applicable 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. The Company has elected to limit its borrowings under the revolving credit facility to cover any potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2020, PGE had no commercial paper outstanding.

PGE typically classifies borrowings under the revolving credit facility and outstanding commercial paper as Short-term debt in the consolidated balance sheets.

Under the revolving credit facility, as of December 31, 2020, PGE had no borrowings or commercial paper outstanding, and no letters of credit issued. As a result, as of December 31, 2020, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities under which the Company has total capacity of $220 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, letters of credit for a total of $60 million were outstanding as of December 31, 2020.

On April 9, 2020, PGE obtained a 364-day term loan from lenders in the aggregate principal of $150 million. The term loan bears interest for the relevant interest period at LIBOR plus 1.25%. The interest rate is subject to adjustment pursuant to the terms of the loan. The credit agreement is classified as Short-term debt on the Company’s consolidated balance sheets and expires on April 8, 2021, with any outstanding balance due and payable on such date.

*Long-term Debt*—During 2020, PGE issued a total of $430 million of FMBs.

On April 27, 2020, PGE issued $200 million of 3.15% Series FMBs due in 2030.

On December 10, 2020, the Company issued to certain institutional buyers in the private placement market $230 million aggregate principal amount of the Company's FMBs that consisted of:

- a series, due in 2027, in the amount of $160 million that will bear interest from its issuance date at an annual rate of 1.84%; and
- a series, due in 2032, in the amount of $70 million that will bear interest from its issuance date at an annual rate of 2.32%.

*Pollution Control Revenue Bonds*—On March 11, 2020, PGE completed the remarketing of an aggregate principal amount of $119 million of Pollution Control Revenue Refunding Bonds (PCRBs), which consist of $98 million aggregate principal of PCRBs that bear an interest rate of 2.125%, and $21 million aggregate principal of PCRBs that bear an interest rate of 2.375%, both due in 2033. At the time of remarketing, the Company chose a new interest rate period that was fixed term. The new interest rate was based on market conditions at the time of remarketing. The PCRBs are backed by the Company’s Indenture of Mortgage by way of FMBs. Interest is payable semi-annually on the PCRBs.

As of December 31, 2020, total long-term debt outstanding, net of $13 million of unamortized debt expense, was $3,046 million, of which $160 million is scheduled to mature in 2021.

*Capital Structure*—PGE’s financial objectives include maintaining a common equity ratio (common equity to total consolidated capitalization, including current debt maturities and excluding lease obligations) of approximately 50% over time. Achievement of this objective helps the Company maintain investment grade debt ratings and provides access to long-term capital at favorable interest rates. The Company’s common equity ratio was 45.0% and 49.9% as of December 31, 2020 and 2019, respectively.

### *Contractual Obligations and Commercial Commitments*

The following table presents PGE's contractual obligations as of December 31, 2020 (in millions):

| | 2021 | 2022 | 2023 | 2024 | 2025 | There-after | Total |
|---|---|---|---|---|---|---|---|
| Long-term debt | $ 160 | $ — | $ — | $ 80 | $ — | $2,819 | $ 3,059 |
| Interest on long-term debt (1) | 126 | 124 | 124 | 124 | 121 | 1,806 | 2,425 |
| Capital and other purchase commitments | 237 | 33 | 20 | 1 | 1 | 55 | 347 |
| Purchased power and fuel: | | | | | | | |
| Electricity purchases | 250 | 257 | 284 | 278 | 249 | 2,886 | 4,204 |
| Capacity contracts | 9 | 9 | 9 | 9 | 9 | — | 45 |
| Public Utility Districts | 21 | 19 | 18 | 17 | 17 | 39 | 131 |
| Natural gas | 57 | 42 | 37 | 43 | 43 | 578 | 800 |
| Coal and transportation | 27 | 27 | 27 | 27 | 27 | — | 135 |
| Pension Plan Contributions (2) | — | — | 16 | 23 | 23 | — | 62 |
| Finance and operating lease obligations | 24 | 24 | 22 | 21 | 14 | 267 | 372 |
| Total | $ 911 | $ 535 | $ 557 | $ 623 | $ 504 | $8,450 | $ 11,580 |

(1) Future interest on long-term debt is calculated based on the assumption that all debt remains outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect as of December 31, 2020.

(2) Contributions beyond 2025 are not estimated due to significant uncertainty in financial market and demographic outcomes.

### *Other Financial Obligations*

PGE has long-term power purchase agreements in place with certain public utility districts in the state of Washington.

The Company has acquired a percentage of the output of the Priest Rapids and Wanapum Hydroelectric Projects under an agreement that requires PGE to pay its proportionate share of the operating and debt service costs of the projects, whether or not they are operable. The agreements further 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 both the output and the operating and debt service costs of the defaulting purchaser.

Under an agreement for output of Douglas County PUD's Wells Hydroelectric Project, PGE receives a share of the production in return for a fixed payment. If any other purchaser of output were to default, PGE would receive a pro-rata portion of the defaulting purchaser's share of the project output and associated costs, with no limitation, regardless of the reason for the default. The share of the project output is expected to decline over time as the public utility district load grows and output is needed to serve that growth.

For additional information on these long-term power purchase agreements, see "*Public utility districts*" in Note 16, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

### *Off-Balance Sheet Arrangements*

Other than the items listed below, PGE has no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on its consolidated financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources:

- PGE has four letter of credit facilities that provide capacity up to a total of $220 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these facilities, $60 million has been issued as of December 31, 2020; and
- As a co-owner of Colstrip, PGE has provided surety bonds of $30 million as of December 31, 2020 on behalf of the operator to ensure the operation and maintenance of remedial and closure actions are carried out related to the Administrative Order on Consent Regarding Impacts Related to Wastewater Facilities Comprising the Closed-Loop System at Colstrip Steam Electric Station, Colstrip Montana (the AOC) as required by the Montana Department of Environmental Quality. It is possible that each co-owner of Colstrip will be required, at some future point, to post additional financial assurance to support further performance by the operator of closure and remediation actions under the AOC.

***Critical Accounting Policies and Estimates***

The preparation of consolidated financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect amounts reported in the statements. The following accounting policies represent those that management believes are particularly important to the consolidated financial statements and that require the use of estimates, assumptions, and judgments to determine matters that are inherently uncertain.

*Regulatory Accounting*

As a rate-regulated enterprise, PGE applies regulatory accounting, which includes the recognition of regulatory assets and liabilities on the Company's consolidated balance sheets. Regulatory assets represent probable future revenue associated with certain incurred costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited or refunded to customers through the ratemaking process. Regulatory accounting is appropriate as long as prices are established or subject to approval by independent third-party regulators, prices are designed to recover the specific enterprise's cost of service, and, in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Amortization of regulatory assets and liabilities is reflected in the statement of income over the period in which they are included in customer prices.

If future recovery of regulatory assets is not probable, PGE would expense such items in the period such determination is made. Further, if PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of regulatory accounting, the Company would be required to write off those regulatory assets and liabilities related to operations that no longer meet requirements for regulatory accounting. Discontinued application of regulatory accounting would have a material impact on the Company's results of operations and financial position.

*Asset Retirement Obligations*

PGE recognizes AROs for legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Upon initial recognition of AROs that are measurable, the probability-weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. In estimating the liability, management must utilize significant judgment and assumptions in determining whether a legal obligation exists to remove assets. Other estimates may be related to lease provisions, ownership agreements, licensing issues, cost estimates, inflation, and certain legal requirements. Estimates for ARO liabilities are generally based on site-specific studies and are periodically subject to updates and changes that may arise over time.

Capitalized asset retirement costs related to electric utility plant are depreciated over the estimated life of the related asset and included in Depreciation and amortization expense in the consolidated statements of income. For revisions to ARO liabilities in which the related asset is no longer in service, the corresponding offset is recorded as a Regulatory asset on the consolidated balance sheets, except for those AROs related to non-utility assets which is charged to Depreciation and amortization on the consolidated statements of income. Accretion of the ARO liability is classified as Depreciation and amortization expense in the consolidated statements of income. Accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from accumulated depreciation to regulatory liabilities in the consolidated balance sheets.

*Contingencies*

PGE has various unresolved legal and regulatory matters about which there is inherent uncertainty, with the ultimate outcome contingent upon several factors. Such contingencies are evaluated using the best information available. A loss contingency is accrued, and disclosed if material, when it is probable that an asset has been impaired, or a liability incurred, and the amount of the loss can be reasonably estimated. If a range of probable loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency and the reasons to the effect that it cannot be reasonably estimated are disclosed. Material loss contingencies are disclosed when it is reasonably possible that an asset has been impaired, or a liability incurred. Established accruals reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the process. There can be no assurance as to the ultimate outcome of any particular contingency.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

PGE is exposed to various forms of market risk, consisting primarily of fluctuations in commodity prices, foreign currency exchange rates, and interest rates, as well as credit risk. Any variations in the Company's market risk or credit risk may affect its future financial position, results of operations, or cash flows, as discussed below.

***Energy Risk Management***

During 2020, PGE had a Risk Management Committee (RMC), whose responsibilities included providing oversight of the adequacy and effectiveness of corporate policies, guidelines, and procedures for market and credit risk management related to the Company's energy portfolio management activities. The RMC consisted of officers and Company representatives with responsibility for risk management, finance and accounting, information technology, utility operations, legal, and rates and regulatory affairs. The RMC reviewed and approved adoption of policies and procedures, and monitored compliance with policies, procedures, and limits on a regular basis through reports and meetings. The RMC also reviewed and recommended risk limits that were subject to approval by PGE's Board of Directors.

In response to the energy trading losses realized in the third quarter of 2020 (for more information see "Energy Trading" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations.") the Company began taking actions to enhance oversight of energy trading and associated risk management reporting, policies, and practices. As a result, effective February 1, 2021, the RMC has been subsumed by the Executive Risk Committee (ERC) whose primary purpose is to oversee, guide, and support the prudent management of the Company's risks. In addition to assuming the responsibilities previously held by the RMC, the ERC's responsibilities have been enhanced to include improved risk reporting to ensure greater visibility into portfolio risk and manage alignment with the Company's Board-approved risk strategy and tolerances.

***Commodity Price Risk***

PGE is exposed to commodity price risk as its primary business is to provide electricity to its retail customers. The Company engages in price risk management activities to manage exposure to volatility in net power costs for its retail customers. The Company uses power purchase and sale contracts to supplement its own generation and to respond to fluctuations in the demand for electricity and variability in generating plant operations. The Company also enters into contracts for the purchase and sale of fuel for the Company's natural gas- and coal-fired generating plants. These contracts for the purchase of power and fuel expose the Company to market risk. The Company uses instruments such as: i) forward contracts, which may involve physical delivery of an energy commodity; ii) financial swap and futures agreements, which may require payments to, or receipt of payments from, counterparties based on the differential between a fixed and variable price for the commodity; and iii) option contracts to mitigate risk that arises from market fluctuations of commodity prices. The Company does not intend to engage in trading activities for non-retail purposes.

A portion of PGE's energy portfolio subject to commodity price risk experienced significant losses during the third quarter of 2020. In August 2020, wholesale electricity prices increased substantially at various market hubs due to extreme weather conditions, constraints to regional transmission facilities, and changes in power supply in the West. As a result of the convergence of these conditions, the Company's energy portfolio experienced realized losses of $127 million in the third quarter of 2020. PGE no longer has net market exposure related to these positions and will not pursue regulatory recovery of the related losses. For additional information see "Energy Trading" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Assuming no changes in market prices and interest rates, the following table presents the years in which the net unrealized (gains)/losses recorded as of December 31, 2020 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

| | 2021 | 2022 | 2023 | 2024 | 2025 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Commodity contracts: | | | | | | | |
| Electricity | $ 9 | $ 4 | $ 8 | $ 8 | $ 9 | $ 100 | $ 138 |
| Natural gas | (27) | (5) | — | — | — | — | (32) |
| Net unrealized (gain)/loss | $ (18) | $ (1) | $ 8 | $ 8 | $ 9 | $ 100 | $ 106 |

PGE reports energy commodity derivative fair values as a net asset or liability, which combines purchases and sales expected to settle in the years noted above. Energy commodity fair values exposed to commodity price risk are primarily related to purchase contracts, which are slightly offset by sales.

PGE's energy portfolio activities are subject to regulation, with related costs included in retail prices approved by the OPUC. The timing differences between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in prices are deferred as regulatory assets and regulatory liabilities to reflect the effects of regulation, significantly mitigating commodity price risk for the Company. As contracts are settled, these deferrals reverse and are recognized as Purchased power and fuel in the statements of income and expected to be included in the PCAM. PGE remains subject to cash flow risk in the form of collateral requirements based on the value of open positions and regulatory risk if recovery is disallowed by the OPUC. PGE attempts to mitigate both types of risks through prudent energy procurement practices.

***Foreign Currency Exchange Rate Risk***

PGE is exposed to foreign currency risk associated with natural gas forward and swap contracts denominated in Canadian dollars. Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. PGE mitigates its exposure to fluctuations in the Canadian exchange rate with an appropriate hedging strategy.

As of December 31, 2020, a 10% change in the value of the Canadian dollar would result in an immaterial change in exposure for transactions that will settle over the next twelve months.

### *Interest Rate Risk*

To meet short-term cash requirements, PGE has the ability to issue commercial paper for terms of up to 270 days and has a revolving credit facility that permits same day borrowings. Although any borrowings under the commercial paper program or the revolving credit facility carry a fixed rate during their respective terms, the short-term nature of such borrowings subjects the Company to fluctuations in interest rates that result from changes in market conditions. As of December 31, 2020, PGE had no borrowings outstanding under its revolving credit facility and no commercial paper outstanding.

PGE currently has no financial instruments to mitigate risk related to changes in short-term interest rates, including those on commercial paper; however, it may consider such instruments in the future as considered necessary.

As of December 31, 2020, the total fair value and carrying amounts, excluding unamortized debt expense, by maturity date of PGE's long-term debt are as follows (in millions):

| | Total Fair Value | Carrying Amounts by Maturity Date | | | | | |
|---|---|---|---|---|---|---|---|
| | | Total | 2021 | 2022 | 2023 | 2024 | There-after |
| First Mortgage Bonds | $ 3,683 | $ 2,940 | $ 160 | $ — | $ — | $ 80 | $ 2,700 |
| Pollution Control Revenue Bonds | 125 | 119 | — | — | — | — | 119 |
| Total | $ 3,808 | $ 3,059 | $ 160 | $ — | $ — | $ 80 | $ 2,819 |

As of December 31, 2020, PGE had no long-term debt instruments subject to interest rate risk exposures.

### *Credit Risk*

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by counterparties. The Company manages the risk of counterparty default according to its credit policies by performing financial credit reviews, setting limits and monitoring exposures, and requiring collateral (in the form of cash, letters of credit, and guarantees) when needed. PGE also uses standardized enabling agreements and, in certain cases, master netting agreements, which allow for the netting of positive and negative exposures under multiple agreements with counterparties. Despite such mitigation efforts, defaults by counterparties may periodically occur. Based upon periodic review and evaluation, allowances are recorded as needed to reflect credit risk related to wholesale accounts receivable.

The large number and diversified base of residential, commercial, and industrial customers, combined with the Company's ability to discontinue service, contribute to reduce credit risk with respect to trade accounts receivable from retail sales. Estimated provisions for uncollectible accounts receivable related to retail sales are provided for such risk.

As of December 31, 2020, PGE's credit risk exposure is $48 million for commodity activities, of which $46 million is with externally-rated investment grade counterparties. The underlying transactions that make up the exposure will mature from 2021 to 2024. The exposure is included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

Investment grade counterparties include those with a minimum credit rating on senior unsecured debt of Baa3 (as assigned by Moody's) or BBB- (as assigned by S&P), and also those counterparties whose obligations are guaranteed or secured by an investment grade entity. The credit exposure includes activity for electricity and natural gas forward, swap, and option contracts. Posted collateral may be in the form of cash or letters of credit, and may represent prepayment or credit exposure assurance.

Omitted from the market risk exposures discussed above are long-term power purchase contracts with certain public utility districts in the state of Washington. These contracts currently provide PGE with a percentage share of hydro facility output in exchange for an equivalent percentage share of operating and debt service costs. These contracts expire at varying dates through 2052. For additional information, see "*Public utility districts*" in Note 16, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data." Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The following financial statements and report are included in Item 8:



## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Portland General Electric Company

### Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2020 and 2019, the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2020, and the related notes (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

### Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

**Definition and Limitations of Internal Control over Financial Reporting**

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

**Critical Audit Matter**

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

**Regulatory Accounting - Refer to Notes 2 and 7 to the financial statements**

*Critical Audit Matter Description*

The Company is subject to rate regulation by the Public Utility Commission of Oregon (the OPUC), which has jurisdiction with respect to the rates for retail electricity in the state of Oregon. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as electric utility plant; regulatory assets and liabilities; operating revenues; operation and maintenance expense; income taxes; and depreciation expense.

The Company's rates for retail customers are determined and approved in regulatory proceedings based on an analysis of the Company's cost of providing service to retail customers. The OPUC has the authority to disallow the recovery of any costs that it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just and reasonable, it has significant discretion in the interpretation of this standard.

We identified the impact of rate regulation as a critical audit matter due to its pervasive impact on the Company's financial statements and the significant judgments made by management to support its assertions about impacted account balances and disclosures. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the OPUC, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process.

*How the Critical Audit Matter Was Addressed in the Audit*

Our audit procedures related to the uncertainty of future decisions by the OPUC included the following, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a refund or future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the OPUC for the Company, regulatory statutes, and other publicly available information to assess the likelihood of recovery in future rates or of a refund or future reduction in rates.
- For selected regulatory assets and liabilities, we evaluated whether management had determined such amounts in accordance with the regulatory orders.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 18, 2021

We have served as the Company's auditor since 2004.

**PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF INCOME**
(Dollars in millions, except per share amounts)

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| **Revenues:** | | | |
| Revenues, net | $ 2,151 | $ 2,121 | $ 1,988 |
| Alternative revenue programs, net of amortization | (6) | 2 | 3 |
| Total Revenues | 2,145 | 2,123 | 1,991 |
| **Operating expenses:** | | | |
| Purchased power and fuel | 708 | 614 | 571 |
| Generation, transmission and distribution | 293 | 323 | 292 |
| Administrative and other | 283 | 290 | 271 |
| Depreciation and amortization | 454 | 409 | 382 |
| Taxes other than income taxes | 138 | 134 | 129 |
| Total operating expenses | 1,876 | 1,770 | 1,645 |
| Income from operations | 269 | 353 | 346 |
| **Interest expense, net** | 136 | 128 | 124 |
| **Other income:** | | | |
| Allowance for equity funds used during construction | 16 | 10 | 11 |
| Miscellaneous income (expense), net | 6 | 6 | (4) |
| Other income, net | 22 | 16 | 7 |
| Income before income taxes | 155 | 241 | 229 |
| **Income tax expense** | — | 27 | 17 |
| **Net income** | $ 155 | $ 214 | $ 212 |
| | | | |
| Weighted-average shares outstanding (in thousands): | | | |
| Basic | 89,485 | 89,353 | 89,215 |
| Diluted | 89,645 | 89,559 | 89,347 |
| | | | |
| **Earnings per share:** | | | |
| Basic | $ 1.73 | $ 2.39 | $ 2.38 |
| Diluted | $ 1.72 | $ 2.39 | $ 2.37 |

*See accompanying notes to consolidated financial statements.*

**PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
(In millions)

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| **Net income** | $ 155 | $ 214 | $ 212 |
| Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of $1 million in 2020 and immaterial amounts in 2019 and 2018 | (1) | (1) | 1 |
| **Comprehensive income** | $ 154 | $ 213 | $ 213 |

*See accompanying notes to consolidated financial statements.*

**PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS**
(In millions)

| | As of December 31, | |
|---|---|---|
| | **2020** | **2019** |
| **ASSETS** | | |
| **Current assets:** | | |
| Cash and cash equivalents | $ 257 | $ 30 |
| Accounts receivable, net | 271 | 253 |
| Inventories, at average cost: | | |
| Materials and supplies | 49 | 56 |
| Fuel | 23 | 40 |
| Regulatory assets—current | 23 | 17 |
| Other current assets | 98 | 104 |
| **Total current assets** | 721 | 500 |
| **Electric utility plant:** | | |
| In service | 10,974 | 10,928 |
| Accumulated depreciation and amortization | (3,864) | (4,095) |
| In service, net | 7,110 | 6,833 |
| Construction work-in-progress | 429 | 328 |
| **Electric utility plant, net** | 7,539 | 7,161 |
| Regulatory assets—noncurrent | 569 | 483 |
| Nuclear decommissioning trust | 45 | 46 |
| Non-qualified benefit plan trust | 42 | 38 |
| Other noncurrent assets | 153 | 166 |
| **Total assets** | $ 9,069 | $ 8,394 |

*See accompanying notes to consolidated financial statements.*

**PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS, continued**
(In millions, except share amounts)

| | As of December 31, | |
|---|---|---|
| | 2020 | 2019 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current liabilities:** | | |
| Accounts payable | $ 153 | $ 165 |
| Liabilities from price risk management activities—current | 14 | 23 |
| Short-term debt | 150 | — |
| Current portion of long-term debt | 160 | — |
| Current portion of finance lease obligations | 16 | 16 |
| Accrued expenses and other current liabilities | 322 | 315 |
| **Total current liabilities** | 815 | 519 |
| Long-term debt, net of current portion | 2,886 | 2,597 |
| Regulatory liabilities—noncurrent | 1,369 | 1,377 |
| Deferred income taxes | 374 | 378 |
| Unfunded status of pension and postretirement plans | 299 | 247 |
| Liabilities from price risk management activities—noncurrent | 136 | 108 |
| Asset retirement obligations | 270 | 263 |
| Non-qualified benefit plan liabilities | 101 | 103 |
| Finance lease obligations, net of current portion | 129 | 135 |
| Other noncurrent liabilities | 77 | 76 |
| **Total liabilities** | 6,456 | 5,803 |
| **Commitments and contingencies (see notes)** | | |
| **Shareholders' equity:** | | |
| Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding | — | — |
| Common stock, no par value, 160,000,000 shares authorized; 89,537,331 and 89,387,124 shares issued and outstanding as of December 31, 2020 and 2019, respectively | 1,231 | 1,220 |
| Accumulated other comprehensive loss | (11) | (10) |
| Retained earnings | 1,393 | 1,381 |
| **Total shareholders' equity** | 2,613 | 2,591 |
| **Total liabilities and shareholders' equity** | $ 9,069 | $ 8,394 |

*See accompanying notes to consolidated financial statements.*

**PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY**
(In millions, except share and per share amounts)

| | Common Stock | | Accumulated Other Comprehensive Loss | Retained Earnings | Total |
|---|---|---|---|---|---|
| | Shares | Amount | | | |
| **Balance as of December 31, 2017** | 89,114,265 | $ 1,207 | $ (8) | $ 1,217 | $ 2,416 |
| Shares issued pursuant to equity-based plans | 153,694 | 1 | — | — | 1 |
| Stock-based compensation | — | 4 | — | — | 4 |
| Dividends declared ($1.4275 per share) | — | — | — | (128) | (128) |
| Net income | — | — | — | 212 | 212 |
| Other comprehensive income | — | — | 1 | — | 1 |
| **Balance as of December 31, 2018** | 89,267,959 | 1,212 | (7) | 1,301 | 2,506 |
| Shares issued pursuant to equity-based plans | 119,165 | 1 | — | — | 1 |
| Stock-based compensation | — | 7 | — | — | 7 |
| Dividends declared ($1.5175 per share) | — | — | — | (136) | (136) |
| Net income | — | — | — | 214 | 214 |
| Reclassification of stranded tax effects due to Tax Reform | — | — | (2) | 2 | — |
| Other comprehensive (loss) | — | — | (1) | — | (1) |
| **Balance as of December 31, 2019** | 89,387,124 | 1,220 | (10) | 1,381 | 2,591 |
| Shares issued pursuant to equity-based plans | 150,207 | 2 | — | — | 2 |
| Stock-based compensation | — | 9 | — | — | 9 |
| Dividends declared ($1.5850 per share) | — | — | — | (143) | (143) |
| Net income | — | — | — | 155 | 155 |
| Other comprehensive (loss) | — | — | (1) | — | (1) |
| **Balance as of December 31, 2020** | 89,537,331 | $ 1,231 | $ (11) | $ 1,393 | $ 2,613 |

*See accompanying notes to consolidated financial statements.*

**PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
(In millions)

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| **Cash flows from operating activities:** | | | |
| **Net income** | $ 155 | $ 214 | $ 212 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and amortization | 454 | 409 | 382 |
| Deferred income taxes | (23) | 6 | (17) |
| Allowance for equity funds used during construction | (16) | (10) | (11) |
| Pension and other postretirement benefits | 22 | 21 | 30 |
| Decoupling mechanism deferrals, net of amortization | 6 | (2) | (2) |
| (Amortization) Deferral of net benefits due to Tax Reform | (23) | (23) | 45 |
| Stock-based compensation | 11 | 9 | 5 |
| Other non-cash income and expenses, net | 22 | 34 | 16 |
| Changes in working capital: | | | |
| (Increase) decrease in receivables and unbilled revenues | (24) | 30 | (29) |
| Decrease (increase) in margin deposits | 8 | — | (5) |
| Increase (decrease) in payables and accrued liabilities | 26 | (16) | 51 |
| Other working capital items, net | 17 | (12) | (11) |
| Contribution to non-qualified employee benefit trust | (11) | (11) | (11) |
| Contribution to pension and other postretirement plans | (2) | (65) | (12) |
| Asset retirement obligation settlements | (18) | (9) | (5) |
| Other, net | (37) | (29) | (8) |
| **Net cash provided by operating activities** | 567 | 546 | 630 |
| **Cash flows from investing activities:** | | | |
| Capital expenditures | (784) | (606) | (595) |
| Purchases of nuclear decommissioning trust securities | (6) | (8) | (12) |
| Sales of nuclear decommissioning trust securities | 9 | 13 | 15 |
| Proceeds from Carty Settlement | — | — | 120 |
| Other, net | (6) | (3) | 1 |
| **Net cash used in investing activities** | (787) | (604) | (471) |

*See accompanying notes to consolidated financial statements.*

## PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
## CONSOLIDATED STATEMENTS OF CASH FLOWS, continued
(In millions)

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| **Cash flows from financing activities:** | | | |
| Proceeds from issuance of long-term debt | $ 549 | $ 470 | $ 75 |
| Payments on long-term debt | (98) | (350) | (24) |
| Debt extinguishment costs | (2) | (9) | — |
| Borrowings on short-term debt | 275 | — | — |
| Payments on short-term debt | (125) | — | — |
| Dividends paid | (140) | (134) | (125) |
| Other | (12) | (8) | (5) |
| **Net cash provided by (used in) financing activities** | 447 | (31) | (79) |
| **Increase (decrease) in cash and cash equivalents** | 227 | (89) | 80 |
| **Cash and cash equivalents, beginning of year** | 30 | 119 | 39 |
| **Cash and cash equivalents, end of year** | $ 257 | $ 30 | $ 119 |
| | | | |
| **Supplemental disclosures of cash flow information:** | | | |
| Cash paid for: | | | |
| Interest, net of amounts capitalized | $ 113 | $ 116 | $ 117 |
| Income taxes | 17 | 33 | 25 |
| Non-cash investing and financing activities: | | | |
| Accrued capital additions | 72 | 76 | 61 |
| Accrued dividends payable | 38 | 36 | 34 |
| Assets obtained under leasing arrangements | — | 210 | 24 |

*See accompanying notes to consolidated financial statements.*

## 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 four thousand square mile, state-approved service area is located entirely within the state of Oregon. PGE's allocated service area includes 51 incorporated cities. As of December 31, 2020, PGE served approximately 908 thousand retail customers with a service area population of approximately 1.9 million.

As of December 31, 2020, PGE had 3,639 members in its workforce (769 of which are contingent workers), with 721 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. The agreements cover 660 and 61 employees and expire March 2022 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.

### *Consolidation Principles*

The consolidated financial statements include the accounts of PGE and its wholly-owned subsidiaries. The Company's ownership share of direct expenses and costs related to jointly-owned generating plants are also included in its consolidated financial statements. For further information on PGE's jointly-owned plant, see Note 18, Jointly-Owned Plant. Intercompany balances and transactions have been eliminated.

### *Use of Estimates*

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP) 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.

### *Reclassifications*

To conform with current year presentation, the Company has reclassified Asset retirement obligation settlements of $9 million and $5 million from Other, net in the operating activities section of the consolidated statements of cash flows for the years ended December 31, 2019 and 2018, respectively.

## NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### *Cash Equivalents*

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents, of which PGE had $255 million as of December 31, 2020 and $26 million as of December 31, 2019 included within Cash and cash equivalents in the consolidated balance sheets.

### *Accounts Receivable*

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 8 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. During 2020, the Company has taken steps to support customers during the COVID-19 pandemic, including suspending disconnections and late fees and developing time payment arrangements.

Provisions for uncollectible accounts receivable and unbilled revenues related to retail sales are charged to Administrative and other expense and are recorded in the same period as the related revenues, with an offsetting credit to the allowance for uncollectible accounts. Such estimates for credit losses are based on management's assessment of the current and forecasted probability of collection, aging of accounts receivable, bad debt write-offs experience, actual customer billings, economic conditions, and other factors that help determine credit loss estimates for accounts receivable and unbilled revenues.

Provisions for uncollectible accounts receivable related to wholesale sales are charged to Purchased power and fuel expense 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 2020, 2019, or 2018.

### *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 consolidated balance sheets as assets or liabilities from price risk management activities. Changes in fair value are recognized in the consolidated statements of income, offset by the effects of regulatory accounting when it is expected that the gain or loss upon settlement will be reflected in future retail rates. 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 variable power costs (NVPC).

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 Revenues, net and Purchased power and fuel expense, respectively, upon settlement, while transactions that are not physically settled (financial transactions) are recorded on a net basis in Purchased power and fuel expense upon financial settlement.

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral to 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 included within Other current assets in the consolidated balance sheets and were $8 million as of December 31, 2020 and $16 million as of December 31, 2019. Letters of credit provided as collateral are not recorded on the Company's consolidated balance sheets and were $12 million and $15 million as of December 31, 2020 and 2019, 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 inventories are recorded at the lower of average cost or net realizable value.

***Electric Utility Plant***

*Capitalization Policy*

Electric 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 in Electric utility plant on the consolidated balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any costs are expensed, 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. On June 30, 2020 the FERC issued a waiver that provides that, for the 12-month period starting March 2020, jurisdictional utilities may apply an alternative AFDC calculation formula that excludes the actual outstanding short-term debt balance and replaces it with the simple average of the actual 2019 short-term debt balance. The purpose of the waiver is to allow relief from the detrimental impacts of issuing short-term debt on the allowance for equity funds used during construction in response to COVID-19. PGE adopted the waiver in the second quarter of 2020. AFDC is capitalized as part of the cost of plant and credited to the consolidated statements of income. The average rate used by PGE was 6.9% in 2020, 7.1% in 2019, and 7.3% in 2018. AFDC from borrowed funds, reflected as a reduction to Interest expense, net, was $8 million in 2020, $5 million in 2019, and $6 million in 2018. AFDC from equity funds, included in Other income, net, was $16 million in 2020, $10 million in 2019, and $11 million in 2018.

*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 3.5% in 2020 and 3.6% in both 2019 and 2018. 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. In 2016 PGE completed a depreciation study based on 2015 data, 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 2061. 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 | 97 |
| Wind | 31 |
| Transmission | 58 |
| Distribution | 46 |
| General | 13 |

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 asset retirement removal costs, if applicable, and included in Regulatory liabilities.

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 $388 million and $366 million as of December 31, 2020 and 2019, respectively, with amortization expense of $64 million in 2020, $64 million in 2019, and $59 million in 2018. Future estimated amortization expense as of December 31, 2020 is as follows: $57 million in 2021; $51 million in 2022; $42 million in 2023; $37 million in 2024; and $25 million in 2025.

***Marketable Securities***

*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 decommissioned 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 investments held therein.

All of PGE's investments in marketable securities included in NDT and NQBP trust on the consolidated balance sheets, 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 NQBP trust assets are included in Other income, net. Realized and unrealized gains and losses on the NDT fund assets are recorded as regulatory liabilities or assets, respectively, for future ratemaking treatment. The cost of securities sold in the NDT is based on the average cost method whereas cost of securities sold in the NQBP is based on the first in first out 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 consolidated 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 7, 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, future customer prices can be adjusted to reflect a portion of the difference between: i) NVPC forecast each year and included in customer prices (baseline NVPC); and ii) actual NVPC for the year. 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 and fuel in the Company's consolidated statements of income, and is net of wholesale sales, which are classified as Revenues, net in the consolidated statements 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 2020, 2019, and 2018.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues, net in PGE's consolidated statements of income, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense. For the year ended December 31, 2020, PGE's actual NVPC was $114 million above baseline NVPC. PGE excluded from actual NVPC and will not be pursuing regulatory recovery for amounts related to trading positions that resulted in realized losses of $127 million during the third quarter of 2020. These losses were the result of a convergence of increased wholesale electricity prices at various market hubs due to extreme weather conditions, constraints to regional transmission facilities and changes in power supply in the West that occurred in August 2020. The Company no longer has net market exposure from these trading positions. After adjusting for the realized losses on the trading positions, PGE's actual NVPC for 2020 was $13 million below baseline NVPC, which is within the established deadband range resulting in no estimated refund to customers.

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 consolidated balance sheets. 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. The present value of estimated future decommissioning costs is capitalized and included in Electric utility plant, net on the consolidated balance sheets with a corresponding offset to ARO. For revisions to AROs in which the related asset is no longer in service, the corresponding offset is recorded as a Regulatory asset on the consolidated balance sheets, except for those AROs related to non-utility assets which is charged to Depreciation and amortization on the consolidated statements of income. Such estimates are revised periodically, with actual settlements charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, with such depreciation included in Depreciation and amortization in the consolidated statements 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 and amortization expense in the Company's consolidated statements of income.

For additional information concerning the Company's AROs, see Note 8, 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 consolidated balance sheets. As of December 31, 2020, PGE had a net regulatory liability related to Utility plant AROs in the amount of $37 million and a net regulatory asset related to Trojan decommissioning ARO activities of $88 million. As of December 31, 2019, PGE had a net regulatory liability related to Utility plant AROs in the amount of $54 million and a net regulatory asset related to Trojan decommissioning ARO activities of $91 million. For additional information concerning the Company's regulatory assets and liabilities related to AROs, see Note 7, Regulatory Assets and Liabilities.

***Contingencies***

Contingencies are evaluated using the best information available at the time the consolidated 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 why the estimate cannot be made.

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

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

For additional information concerning the Company's contingencies, see Note 19, Contingencies.

***Accumulated Other Comprehensive Loss***

Accumulated other comprehensive loss (AOCL) presented on the consolidated balance sheets is comprised of the difference between the obligations of the non-qualified benefit plans 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 services provided, are regulated by the OPUC or the 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 consolidated statements of income. Amounts collected from customers are included in Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $46 million in 2020 and $45 million in both 2019 and 2018.

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 remained unbilled to customers. The unbilled revenues estimate, which is included in Accounts receivable, net in the Company's consolidated balance sheets, 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.

***Alternative Revenue Programs***

Revenues related to PGE's decoupling mechanism are considered earned under alternative revenue programs, as this amount represents a contract with the regulator and not with customers. Such revenues are presented separately from revenues from contracts with customers and classified as Alternative revenue programs, net of amortization on the consolidated statements of income. The activity within this line item is comprised of current period deferral adjustments, which can either be a collection from or a refund to customers, and is net of any related amortization. When amounts related to alternative revenue programs are ultimately included in prices and customer bills, the amounts are included within Revenues, net, with an equal and offsetting amount of amortization recorded on the Alternative revenue programs, net of amortization line item.

***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 14, 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.

Because PGE is a rate-regulated enterprise, changes in certain deferred tax assets and liabilities are required to be passed on to customers through future prices and are charged or credited directly to a regulatory asset or regulatory liability. Such amounts were recognized as net regulatory liabilities of $239 million and $260 million as of December 31, 2020 and 2019, respectively, and will primarily be amortized using the average rate assumption method to account for the refund to customers as the temporary differences reverse.

Unrecognized tax benefits represent management's expected treatment of a tax position taken in a filed tax return or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are no longer considered uncertain, PGE would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company's consolidated balance sheets.

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

***Recently Adopted Accounting Pronouncements***

On January 1, 2020, PGE adopted 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 disclosures. As the standard relates only to disclosures, the implementation did not result in an impact to the results of operation, financial position or cash flows.

On January 1, 2020, PGE adopted 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.* ASU 2018-15 provides guidance on implementation costs incurred in a cloud computing arrangement that is a service contract and aligns the accounting for such costs with the guidance on capitalizing costs associated with developing or obtaining internal-use software. PGE applied the amendments of this ASU prospectively, and the implementation did not have a material impact on PGE's results of operation, financial position or cash flows.

On January 1, 2020, PGE adopted ASU 2016-13 *Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments.* ASU 2016-13 replaces the incurred loss impairment methodology in previous GAAP with a methodology that reflects expected credit losses, and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. PGE applied this ASU using a modified-retrospective approach, and as a result, amounts recorded prior to January 1, 2020 have not been retrospectively restated. Under the new standard, PGE estimates current expected credit losses for retail sales based on an assessment of the current and forecasted probability of collection, aging of accounts receivable, bad debt write-offs experience, actual customer billings, economic conditions, and other significant events that may impact the collectability of accounts receivable and unbilled revenues. Provisions for current expected credit losses related to retail sales, and changes to the amount of expected credit losses for existing receivables, are charged to Administrative and other expense and are recorded in the same period as the related revenues, with an offsetting credit to the allowance for credit losses. The implementation did not have a material impact on PGE's results of operation, financial position, or cash flows. To conform with 2020 presentation, PGE reclassified $86 million of Unbilled revenues to Accounts receivable, net on the consolidated balance sheets as of December 31, 2019.

On April 1, 2020, PGE adopted ASU 2020-04 *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting.* ASU 2020-04 provides optional guidance for a limited period of time to ease the potential burden in accounting for (or recognizing the effects of) reference rate reform on financial reporting. PGE applied the amendments of this ASU prospectively, and the implementation did not have a material impact on PGE's results of operation, financial position, or cash flows.

PGE has adopted 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. As the standard relates only to disclosures, the adoption did not have a material impact on PGE's results of operation, financial position, or cash flows.

## NOTE 3: REVENUE RECOGNITION

**Disaggregated Revenue**

The following table presents PGE's revenue, disaggregated by customer type (in millions):

| | Year Ended December 31, 2020 | Year Ended December 31, 2019 |
|---|---|---|
| Retail: | | |
| Residential | $ 1,030 | $ 981 |
| Commercial | 616 | 636 |
| Industrial | 218 | 196 |
| Direct access customers | 46 | 44 |
| Subtotal | 1,910 | 1,857 |
| Alternative revenue programs, net of amortization | (6) | 2 |
| Other accrued (deferred) revenues, net[1] | 28 | 22 |
| Total retail revenues | 1,932 | 1,881 |
| Wholesale revenues[2] | 162 | 170 |
| Other operating revenues | 51 | 72 |
| Total revenues | $ 2,145 | $ 2,123 |

(1) Amounts for the year ended December 31, 2020 and 2019 is primarily comprised of $24 million and $23 million of amortization, respectively, including interest, related to the net tax benefits due to the change in corporate tax rate under the United States Tax Cuts and Jobs Act of 2017 (TCJA).
(2) Wholesale revenues include $65 million and $50 million related to physical electricity commodity contract derivative settlements for the years ended December 31, 2020 and 2019, respectively. Price risk management derivative activities are included within Total revenues but do not represent revenues from contracts with customers as defined by GAAP, pursuant to Topic 606. For further information, see Note 6, Risk Management.

***Retail Revenues***

The Company's primary revenue source is the sale of electricity to customers at regulated tariff-based prices. Retail customers are classified as residential, commercial, or industrial. Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), manufactured homes, and small farms. Residential demand is sensitive to the effects of weather, with demand highest during the winter heating and summer cooling seasons. Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers and are also sensitive to the effects of weather, although to a lesser extent than residential customers. Commercial customers include most businesses, small industrial companies, and public street and highway lighting accounts. Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on energy use by this customer class.

In accordance with state regulations, PGE's retail customer prices are based on the Company's cost of service and determined through general rate case proceedings and various tariff filings with the OPUC. Additionally, the Company offers pricing options that include a daily market price option, various time-of-use options, and several renewable energy options.

Retail revenue is billed based on monthly meter readings taken throughout the month. At the end of each month, PGE estimates the revenue earned from energy deliveries that have not yet been billed to customers. This amount, classified as Unbilled revenues, which is included in Accounts receivable, net in the Company's consolidated balance sheets, 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.

PGE's obligation to sell electricity to retail customers generally represents a single performance obligation representing a series of distinct services that are substantially the same and have the same pattern of transfer to the customer that is satisfied over time as customers simultaneously receive and consume the benefits provided. PGE applies the invoice method to measure its progress towards satisfactorily completing its performance obligations.

Pursuant to regulation by the OPUC, PGE is mandated to maintain several tariff schedules to collect funds from customers for programs that benefit the general public, such as conservation, low-income housing, energy efficiency, renewable energy programs, and privilege taxes. For such programs, PGE generally collects the funds and remits the amounts to third party agencies that administer the programs. In these arrangements, PGE is considered to be an agent, as PGE's performance obligation is to facilitate a transaction between customers and the administrators of these programs. Therefore, such amounts are presented on a net basis and do not appear in Revenues, net within the consolidated statements of income.

***Wholesale Revenues***

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity within the region depending upon the relative price and availability of power, hydro, solar, and wind conditions, and daily and seasonal retail demand.

PGE's Wholesale revenues are primarily short-term electricity sales to utilities and power marketers that consist of single performance obligations that are satisfied as energy is transferred to the counterparty. The Company may choose to net certain purchase and sale transactions in which it would simultaneously receive and deliver physical power with the same counterparty; in such cases, only the net amount of those purchases or sales required to meet retail and wholesale obligations will be physically settled and recorded in Wholesale revenues.

***Other Operating Revenues***

Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Company's generating facilities, as well as revenues from transmission services, excess transmission capacity resale, excess fuel sales, utility pole attachment revenues, and other electric services provided to customers.

## NOTE 4: BALANCE SHEET COMPONENTS

***Accounts Receivable, Net***

Accounts receivable, net includes $97 million and $86 million of unbilled revenues as of December 31, 2020 and 2019, respectively. Accounts receivable is net of an allowance for uncollectible accounts of $16 million as of December 31, 2020 and $5 million as of December 31, 2019. The following is the activity in the allowance for uncollectible accounts (in millions):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Balance as of beginning of year | $ 5 | $ 15 | $ 6 |
| Increase in provision * | 15 | 2 | 14 |
| Amounts written off, less recoveries | (4) | (12) | (5) |
| Balance as of end of year | $ 16 | $ 5 | $ 15 |

* As of December 31, 2020, PGE has deferred as a regulatory asset $8 million in bad debt expense pursuant to the OPUC's COVID-19 deferral order.

***Other Current Assets and Accrued Expenses and Other Current Liabilities***

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

| | As of December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Other current assets: | | |
| Prepaid expenses | $ 57 | $ 63 |
| Margin deposits | 8 | 16 |
| Assets from price risk management activities | 33 | 25 |
| | $ 98 | $ 104 |
| Accrued expenses and other current liabilities: | | |
| Regulatory liabilities—current | $ 23 | $ 44 |
| Accrued employee compensation and benefits | 67 | 74 |
| Accrued dividends payable | 38 | 36 |
| Accrued interest payable | 29 | 25 |
| Accrued taxes payable | 36 | 33 |
| Other | 129 | 103 |
| | $ 322 | $ 315 |

***Electric Utility Plant, Net***

Electric utility plant, net consist of the following (in millions):

| | As of December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Electric utility plant: | | |
| Generation | $ 4,436 | $ 4,749 |
| Transmission | 970 | 848 |
| Distribution | 4,136 | 3,917 |
| General | 679 | 656 |
| Intangible | 753 | 758 |
| Total in service | 10,974 | 10,928 |
| Accumulated depreciation and amortization | (3,864) | (4,095) |
| Total in service, net | 7,110 | 6,833 |
| Construction work-in-progress | 429 | 328 |
| Electric utility plant, net | $ 7,539 | $ 7,161 |

## NOTE 5: 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 consolidated balance sheets, for which it is practicable to estimate fair value as of December 31, 2020 and 2019. 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 that 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, 2020 and 2019, 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, 2020 | | | | |
|---|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Other**[2] | **Total** |
| Assets: | | | | | |
| Cash equivalents | $ 255 | $ — | $ — | $ — | $ 255 |
| Nuclear decommissioning trust: [1] | | | | | |
| Debt securities: | | | | | |
| Domestic government | 9 | 11 | — | — | 20 |
| Corporate credit | — | 13 | — | — | 13 |
| Money market funds measured at NAV [2] | — | — | — | 12 | 12 |
| 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 | — | 4 | 4 | — | 8 |
| Natural gas | — | 36 | 1 | — | 37 |
| | $ 273 | $ 64 | $ 5 | $ 12 | $ 354 |
| Liabilities: | | | | | |
| Price risk management activities: [1] [4] | | | | | |
| Electricity | $ — | $ 5 | $ 141 | $ — | $ 146 |
| Natural gas | — | 4 | 1 | — | 5 |
| | $ — | $ 9 | $ 142 | $ — | $ 151 |

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $33 million, which are recorded at cash surrender value.
(4) For further information regarding price risk management derivatives, see Note 6, Risk Management.

| | As of December 31, 2019 | | | | |
|---|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Other(2)** | **Total** |
| Assets: | | | | | |
| Cash equivalents | $ 26 | $ — | $ — | $ — | $ 26 |
| Nuclear decommissioning trust: (1) | | | | | |
| Debt securities: | | | | | |
| Domestic government | 8 | 16 | — | — | 24 |
| Corporate credit | — | 9 | — | — | 9 |
| Money market funds measured at NAV (2) | — | — | — | 13 | 13 |
| 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 | — | 9 | 7 | — | 16 |
| Natural gas | — | 21 | 1 | — | 22 |
| | $ 43 | $ 55 | $ 8 | $ 13 | $ 119 |
| Liabilities: | | | | | |
| Price risk management activities: (1) (4) | | | | | |
| Electricity | $ — | $ 14 | $ 105 | $ — | $ 119 |
| Natural gas | — | 12 | — | — | 12 |
| | $ — | $ 26 | $ 105 | $ — | $ 131 |

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.
(3) Excludes insurance policies of $29 million, which are recorded at cash surrender value.
(4) For further information regarding price risk management derivatives, see Note 6, Risk Management.

***Cash equivalents*** 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 securities held by the funds do not exceed 90 days and investors have the ability to redeem shares daily at the net asset value of the respective fund. Cash equivalents 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 the National Association of Securities Dealers Automated Quotations (NASDAQ) and the New York Stock Exchange (NYSE).

***Assets held in the NDT and NQBP trusts*** are recorded at fair value in PGE's consolidated balance sheets and invested in securities that are exposed to interest rate, credit, and market volatility risks. These assets are classified within Level 1, 2, or 3 based on the following factors:

> *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 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.

***Assets and liabilities from price risk management activities,*** recorded at fair value in PGE's consolidated balance sheets, consist of derivative instruments entered into by the Company to manage its risk exposure to commodity price and foreign currency exchange rates and reduce volatility in NVPC. For additional information regarding these assets and liabilities, see Note 6, 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, 2020:** | | | | | | | |
| Electricity physical forwards | $ — | $ 141 | Discounted cash flow | Electricity forward price (per MWh) | $ 11.17 | $ 51.18 | $ 29.74 |
| Natural gas financial swaps | 1 | 1 | Discounted cash flow | Natural gas forward price (per Dth) | 1.52 | 4.33 | 2.29 |
| Electricity financial futures | 4 | — | Discounted cash flow | Electricity forward price (per MWh) | 8.78 | 58.42 | 43.71 |
| | $ 5 | $ 142 | | | | | |
| **As of December 31, 2019:** | | | | | | | |
| Electricity physical forwards | $ — | $ 104 | Discounted cash flow | Electricity forward price (per MWh) | $ 12.53 | $ 59.00 | $ 36.92 |
| Natural gas financial swaps | 1 | — | Discounted cash flow | Natural gas forward price (per Dth) | 1.39 | 3.73 | 1.90 |
| Electricity financial futures | 7 | 1 | Discounted cash flow | Electricity forward price (per MWh) | 10.57 | 66.32 | 45.11 |
| | $ 8 | $ 105 | | | | | |

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, | |
|---|---|---|
| | 2020 | 2019 |
| Net liabilities from price risk management activities as of beginning of year | $ 97 | $ 88 |
| Net realized and unrealized losses/(gains) * | 38 | 10 |
| Net transfers from Level 3 to Level 2 | 2 | (1) |
| Net liabilities from price risk management activities as of end of year | $ 137 | $ 97 |
| Level 3 net unrealized losses/(gains) that have been fully offset by the effect of regulatory accounting | $ 47 | $ 16 |

* Includes $9 million in net realized gains in 2020 and $6 million in 2019.

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, 2020 and 2019, 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 into and from 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 consolidated balance sheets. The fair value of the Company's FMBs and Pollution Control Revenue Bonds (PCRBs) is classified as a Level 2 fair value measurement.

As of December 31, 2020, the carrying amount of PGE's long-term debt was $3,046 million, net of $13 million of unamortized debt expense, and its estimated aggregate fair value was $3,808 million. As of December 31, 2019, the carrying amount of PGE's long-term debt was $2,597 million, net of $11 million of unamortized debt expense, with an estimated aggregate fair value of $3,039 million.

For fair value information concerning the Company's pension plan assets, see Note 11, Employee Benefits.

## NOTE 6: RISK MANAGEMENT

### Price Risk Management

PGE participates in the wholesale marketplace 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 the Company's long-term wholesale contracts. Wholesale market transactions include purchases and sales of both power and fuel resulting from economic dispatch decisions with respect to 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 flows.

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign exchange rate risk in order to reduce volatility in NVPC for its retail customers. Such derivative instruments, recorded at fair value on the consolidated balance sheets, may include forward, future, swap, and option contracts for electricity, natural gas, and foreign currency, with changes in fair value recorded in the consolidated statements 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 intend to 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, | |
|---|---|---|
| | 2020 | 2019 |
| **Current assets:** | | |
| Commodity contracts: | | |
| Electricity | $ 4 | $ 9 |
| Natural gas | 29 | 16 |
| Total current derivative assets[1] | 33 | 25 |
| **Noncurrent assets:** | | |
| Commodity contracts: | | |
| Electricity | 4 | 7 |
| Natural gas | 8 | 6 |
| Total noncurrent derivative assets[1] | 12 | 13 |
| Total derivative assets[2] | $ 45 | $ 38 |
| **Current liabilities:** | | |
| Commodity contracts: | | |
| Electricity | $ 13 | $ 14 |
| Natural gas | 2 | 9 |
| Total current derivative liabilities | 15 | 23 |
| **Noncurrent liabilities:** | | |
| Commodity contracts: | | |
| Electricity | 133 | 105 |
| Natural gas | 3 | 3 |
| Total noncurrent derivative liabilities | 136 | 108 |
| Total derivative liabilities[2] | $ 151 | $ 131 |

(1) Total current derivative assets is included in Other current assets, and Total noncurrent derivative assets is included in Other noncurrent assets on the consolidated balance sheets.
(2) As of December 31, 2020 and 2019, no commodity derivative assets or liabilities were designated as hedging instruments.

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, | | | |
|---|---|---|---|---|
| | 2020 | | 2019 | |
| Commodity contracts: | | | | |
| Electricity | 6 | MWh | 6 | MWh |
| Natural gas | 137 | Dth | 145 | Dth |
| Foreign currency contracts | $ 19 | Canadian | $ 23 | Canadian |

PGE has elected to report positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement at gross values on the consolidated balance sheet. 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, 2020, gross amounts included as Price risk management liabilities subject to master netting agreements were $2 million, for which PGE has posted no collateral. Of the gross amounts recognized as of December 31, 2020, $1 million was for electricity and $1 million was for natural gas. As of December 31, 2019, PGE had no material gross master netting arrangements.

Net realized and unrealized losses (gains) on derivative transactions not designated as hedging instruments are classified in Purchased power and fuel in the consolidated statements of income and were as follows (in millions):

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2020** | **2019** | **2018** |
| Commodity contracts: | | | |
| Electricity | $ 160 | $ 20 | $ (34) |
| Natural Gas | (34) | (32) | 21 |
| Foreign currency contracts | (1) | (1) | 1 |

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the consolidated statements of income by the effects of regulatory accounting. Of the net amounts recognized in Net income, net losses of $12 million, net gains of $2 million, and net gains of $18 million for the years ended December 31, 2020, 2019 and 2018, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table presents the years in which the net unrealized (gains)/losses recorded as of December 31, 2020 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

| | **2021** | **2022** | **2023** | **2024** | **2025** | **Thereafter** | **Total** |
|---|---|---|---|---|---|---|---|
| Commodity contracts: | | | | | | | |
| Electricity | $ 9 | $ 4 | $ 8 | $ 8 | $ 9 | $ 100 | $ 138 |
| Natural gas | (27) | (5) | — | — | — | — | (32) |
| Net unrealized (gain)/loss | $ (18) | $ (1) | $ 8 | $ 8 | $ 9 | $ 100 | $ 106 |

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 derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2020 was $148 million, for which the Company has posted $13 million in collateral, consisting of $12 million of letters of credit and $1 million of cash. If the credit-risk-related contingent features underlying these agreements were triggered as of December 31, 2020, the cash requirement to either post as collateral or settle the instruments immediately would have been $142 million. As of December 31, 2020, PGE had $6 million posted cash collateral for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivative instruments is classified as Margin deposits included in Other current assets on the Company's consolidated balance sheet.

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

| | As of December 31, 2020 | As of December 31, 2019 |
|---|---|---|
| **Assets from price risk management activities:** | | |
| Counterparty A | 12 % | 35 % |
| Counterparty B | 17 | 13 |
| Counterparty C | 21 | 11 |
| Counterparty D | 16 | 11 |
| | 66 % | 70 % |
| **Liabilities from price risk management activities:** | | |
| Counterparty E | 93 % | 79 % |

For additional information concerning the determination of fair value for the Company's Assets and Liabilities from price risk management activities, see Note 5, Fair Value of Financial Instruments.

## NOTE 7: 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):

| | | As of December 31, | | | |
|---|---|---|---|---|---|
| | | 2020 | | | 2019 |
| | Remaining Amortization Period | Earning a Return (1) | Not Earning a Return | Total | Total |
| Regulatory assets: | | | | | |
| Price risk management | 2035 | $ — | $ 124 | $ 124 | $ 95 |
| Pension plan | (2) | — | 240 | 240 | 213 |
| Debt issuance costs | 2050 | — | 25 | 25 | 26 |
| Trojan decommissioning activities | 2059 | — | 95 | 95 | 94 |
| Other | Various | 87 | 22 | 109 | 72 |
| Total regulatory assets | | $ 87 | $ 506 | $ 593 | $ 500 |
| Regulatory liabilities: | | | | | |
| Asset retirement removal costs | (3) | $ 1,016 | $ — | $ 1,016 | $ 1,021 |
| Deferred income taxes | (4) | 239 | — | 239 | 260 |
| Asset retirement obligations | (3) | 37 | — | 37 | 54 |
| Tax reform deferral (5) | 2020 | — | — | — | 23 |
| Price risk management | 2021 | — | 18 | 18 | 2 |
| Other | Various | 46 | 36 | 82 | 61 |
| Total regulatory liabilities | | $ 1,338 | $ 54 | $ 1,392 | $ 1,421 |

(1) Earning a return includes either interest on the regulatory asset or liability, or inclusion of the regulatory asset or liability as an increase or decrease to rate base at the allowed rate of return.
(2) Recovery expected over the average service life of employees.
(3) Recovery or refund expected over the estimated lives of the underlying assets and treated as a reduction to rate base.
(4) Refund expected primarily through amortization using the average rate assumption method over the average life of the underlying assets and treated as a reduction to rate base.
(5) Refund related to the deferral of the 2018 net tax benefits due to the change in corporate tax rate under TCJA, including interest, over a two-year period that began in 2019.

*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 6, 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 11, Employee Benefits.

*Debt issuance costs* represents unrecognized debt issuance costs related to debt instruments retired prior to the stipulated maturity date.

*Trojan decommissioning activities* represents the deferral of ongoing costs associated with monitoring spent nuclear fuel at Trojan, net of amortization of customer collections. In addition, proceeds received from the United States Department of Energy (USDOE) for the reimbursement of costs to monitor the ISFSI is deferred and offsets customer collections.

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

*Deferred income taxes* represents income tax benefits primarily from property-related timing differences that will be refunded to customers when the temporary differences reverse. 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 over the book life of the related assets. The Company uses the average rate assumption method to account for the refund to customers. For further information, see Note 12, Income Taxes.

*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 8: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

| | As of December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Trojan decommissioning activities | $ 139 | $ 137 |
| Utility plant | 118 | 126 |
| Non-utility property | 34 | 16 |
| Total asset retirement obligations | 291 | 279 |
| Less: current portion * | 21 | 16 |
| Noncurrent asset retirement obligations | $ 270 | $ 263 |

* Current portion of AROs are classified within Accrued expenses and other current liabilities in the consolidated balance sheets.

*Trojan decommissioning activities* represents the present value of future decommissioning costs for PGE's 67.5% ownership interest in Trojan, 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 will store 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 2059. The Company recorded accretion of $6 million and a reduction of $4 million due to settled liabilities.

Under a settlement agreement reached with the USDOE, the Company receives annual reimbursement from the USDOE for certain costs related to monitoring the ISFSI. Pursuant to this process, the USDOE reimbursed the co-owners $5 million in 2020 for costs incurred in 2019 and $4 million in 2019 for costs incurred in 2018 resulting from USDOE delays in accepting spent nuclear fuel.

*Utility plant* represents AROs that have been recognized for the Company's thermal and wind generation sites, and distribution and transmission assets, the disposal of which is governed by environmental regulation. During 2020, the Company recorded an overall decrease in utility AROs of $8 million, with the change comprised of new liabilities incurred of $5 million, reduction of $4 million due to revisions in estimated cash flows, accretion of $4 million, and a reduction of $13 million due to settled liabilities.

*Non-utility property* primarily represents AROs that have been recognized for portions of unregulated properties that are currently or previously leased to third parties. Revisions to estimates for non-utility AROs relate to assets that are no longer in service and the offset is charged directly to Depreciation and amortization on the consolidated statements of income in the period in which the revisions are probable and reasonably estimate. Non-utility AROs are not subject to regulatory deferral.

In 2020, PGE performed a decommissioning study to update its ARO liability which resulted in a $21 million increase to non-utility property AROs. As part of this study, the Company also established an ARO liability of $3 million related to utility properties and was charged to expense in the consolidated statement of income. PGE plans to pursue regulatory recovery for the utility portion of the ARO update, however as of December 31, 2020 no amounts have been deferred as a regulatory asset.

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Balance as of beginning of year | $ 279 | $ 197 | $ 167 |
| Liabilities incurred | 3 | — | — |
| Liabilities settled | (18) | (9) | (5) |
| Accretion expense | 10 | 9 | 8 |
| Revisions in estimated cash flows | 17 | 82 | 27 |
| Balance as of end of year | $ 291 | $ 279 | $ 197 |

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 with an equal amount recorded in Depreciation and amortization expense.

PGE maintains a separate trust account, Nuclear decommissioning trust in the consolidated balance sheet, for funds collected from customers through prices to cover the cost of Trojan decommissioning activities.

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. Removal costs are charged to accumulated asset retirement removal costs, which is included in Regulatory liabilities on PGE's consolidated balance sheets.

## NOTE 9: CREDIT FACILITIES

As of December 31, 2020, PGE had a $500 million revolving credit facility scheduled to expire in November 2023. The Company has the ability to expand the revolving credit facility to $600 million, if needed. The credit facility allows 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, including 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 consolidated indebtedness, as defined in the agreement, to 65.0% of total capitalization. As of December 31, 2020, PGE was in compliance with this covenant with a 56.4% debt to total capital ratio.

PGE typically classifies borrowings under the revolving credit facility and outstanding commercial paper as Short-term debt in the consolidated balance sheets.

Under the revolving credit facility, as of December 31, 2020, PGE had no borrowings outstanding and there were no commercial paper or letters of credit issued. As a result, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days. The Company has elected to limit its borrowings under the revolving credit facility to cover any potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2020, PGE had no commercial paper outstanding.

In addition, PGE has four letter of credit facilities that provide a total capacity 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, a total of $60 million of letters of credit were outstanding as of December 31, 2020. Outstanding letters of credit are not reflected on the Company's consolidated balance sheets.

On April 9, 2020, PGE obtained a 364-day unsecured term loan from lenders in the aggregate principal of $150 million. The term loan bears interest for the relevant interest period at LIBOR plus 1.25%. The interest rate is subject to adjustment pursuant to the terms of the loan. The credit agreement is classified as Short-term debt on the Company's consolidated balance sheets and expires on April 8, 2021, with any outstanding balance due and payable on such date.

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, 2022.

Short-term borrowings under these credit facilities, and related interest rates, are reflected in the following table (dollars in millions).

| | Year Ended December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Average daily amount of short-term debt outstanding | $ 131 | $ 7 |
| Weighted daily average interest rate * | 1.5 % | 2.6 % |
| Maximum amount outstanding during the year | $ 225 | $ 46 |

* Excludes the effect of commitment fees, facility fees and other financing fees.

The Company had no short-term borrowings during 2018.

## NOTE 10: LONG-TERM DEBT

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

| | As of December 31, | |
|---|---|---|
| | 2020 | 2019 |
| **First Mortgage Bonds**, rates range from 1.84% to 9.31%, with a weighted average rate of 4.14% in 2020 and 4.63% in 2019, due at various dates through 2050 | $ 2,940 | $ 2,510 |
| **Pollution Control Revenue Bonds**, rates at 2.13% and 2.38%, due 2033 | 119 | 119 |
| Pollution Control Revenue Bonds held by PGE | — | (21) |
| Total long-term debt | 3,059 | 2,608 |
| Less: Unamortized debt expense | (13) | (11) |
| Less: Current portion of long-term debt | (160) | — |
| **Long-term debt, net of current portion** | $ 2,886 | $ 2,597 |

*First Mortgage Bonds*—On April 27, 2020, PGE issued $200 million of 3.15% Series FMBs due in 2030.

On December 10, 2020, PGE issued $230 million aggregate principal amount of the Company's FMBs that consisted of:

- a series, due in 2027, in the amount of $160 million that will bear interest from its issuance date at an annual rate of 1.84%; and
- a series, due in 2032, in the amount of $70 million that will bear interest from its issuance date at an annual rate of 2.32%.

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*—On March 11, 2020, PGE completed the remarketing of an aggregate principal amount of $119 million of Pollution Control Revenue Refunding Bonds (PCRBs), which consist of $98 million aggregate principal of PCRBs that bear an interest rate of 2.125%, and $21 million aggregate principal of PCRBs that bear an interest rate of 2.375%, both due in 2033. At the time of remarketing, the Company chose a new interest rate period that was fixed term. The new interest rate was based on market conditions at the time of remarketing. The PCRBs could be backed by FMBs or a bank letter of credit depending on market conditions. Interest is payable semi-annually on the PCRBs.

As of December 31, 2020, the future minimum principal payments on long-term debt are as follows (in millions):

| Years ending December 31: | |
|---|---|
| 2021 | $ 160 |
| 2022 | — |
| 2023 | — |
| 2024 | 80 |
| 2025 | — |
| Thereafter | 2,819 |
| | $ 3,059 |

## NOTE 11: EMPLOYEE BENEFITS

### *Pension and Other Postretirement Plans*

*Defined Benefit Pension Plan*—PGE sponsors a non-contributory defined benefit pension plan, which is 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.

As expected, PGE contributed no additional funds to the pension plan in 2020 after contributing $62 million in 2019. PGE does not expect to contribute to the pension plan in 2021.

*Other Postretirement Benefits*—PGE offers non-contributory postretirement health and life insurance plans, and provides health reimbursement arrangements (HRAs) to its employees (collectively, "Other Postretirement Benefits" in the following tables). PGE's obligation pursuant to the postretirement health plan is limited by establishing a maximum benefit per employee with any additional cost the responsibility of the employee.

The assets of these plans are held in voluntary employees' beneficiary association trusts and are comprised of money market funds, equity securities, 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, bonds, 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. For further information regarding these trust investments, see Note 5, Fair Value of Financial Instruments.

*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. 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 PGE's consolidated balance sheets are as follows as of December 31 (in millions):

| | 2020 | | | 2019 | | |
|---|---|---|---|---|---|---|
| | NQBP | Other NQBP | Total | NQBP | Other NQBP | Total |
| Non-qualified benefit plan trust | $ 19 | $ 23 | $ 42 | $ 17 | $ 21 | $ 38 |
| Non-qualified benefit plan liabilities * | 26 | 75 | 101 | 24 | 79 | 103 |

* For the NQBP, excludes the current portion of $2 million in 2020 and in 2019, which are classified in Accrued expenses and other current liabilities in the consolidated balance sheets.

*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 the implementation of the asset allocation and oversight of the benefit plan investments. The Company's investment strategy 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, | | | |
|---|---|---|---|---|
| | 2020 | | 2019 | |
| | Actual | Target * | Actual | Target * |
| **Defined Benefit Pension Plan:** | | | | |
| Equity securities | 67 % | 65 % | 64 % | 65 % |
| Debt securities | 33 | 35 | 36 | 35 |
| Total | 100 % | 100 % | 100 % | 100 % |
| **Other Postretirement Benefit Plans:** | | | | |
| Equity securities | 60 % | 57 % | 61 % | 59 % |
| Debt securities | 40 | 43 | 39 | 41 |
| Total | 100 % | 100 % | 100 % | 100 % |
| **Non-Qualified Benefits Plans:** | | | | |
| Equity securities | 17 % | 12 % | 17 % | 12 % |
| Debt securities | 6 | 11 | 7 | 12 |
| Insurance contracts | 77 | 77 | 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.

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, 2020:** | | | | | |
| **Defined Benefit Pension Plan assets:** | | | | | |
| Equity securities—Domestic | $ 49 | $ — | $ — | $ — | $ 49 |
| Investments measured at NAV: | | | | | |
| Money market funds | — | — | — | 6 | 6 |
| Collective trust funds | — | — | — | 692 | 692 |
| Private equity funds | — | — | — | 6 | 6 |
| | $ 49 | $ — | $ — | $ 704 | $ 753 |
| **Other Postretirement Benefit Plans assets:** | | | | | |
| Money market funds | $ 4 | $ — | $ — | $ — | $ 4 |
| Equity securities: | | | | | |
| Domestic | — | 3 | — | — | 3 |
| International | 9 | — | — | — | 9 |
| Debt securities—Domestic | — | 5 | — | — | 5 |
| Investments measured at NAV: | | | | | |
| Money market funds | — | — | — | 5 | 5 |
| Collective trust funds | — | — | — | 9 | 9 |
| | $ 13 | $ 8 | $ — | $ 14 | $ 35 |
| **As of December 31, 2019:** | | | | | |
| **Defined Benefit Pension Plan assets:** | | | | | |
| Equity securities—Domestic | $ 49 | $ — | $ — | $ — | $ 49 |
| Investments measured at NAV: | | | | | |
| Money market funds | — | — | — | 5 | 5 |
| Collective trust funds | — | — | — | 632 | 632 |
| Private equity funds | — | — | — | 9 | 9 |
| | $ 49 | $ — | $ — | $ 646 | $ 695 |
| **Other Postretirement Benefit Plans assets:** | | | | | |
| Money market funds | $ 4 | $ — | $ — | $ — | $ 4 |
| Equity securities: | | | | | |
| Domestic | — | 3 | — | — | 3 |
| International | 9 | — | — | — | 9 |
| Debt securities—Domestic government | — | 5 | — | — | 5 |
| Investments measured at NAV: | | | | | |
| Money market funds | — | — | — | 5 | 5 |
| Collective trust funds | — | — | — | 8 | 8 |
| | $ 13 | $ 8 | $ — | $ 13 | $ 34 |

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

An overview of the identification of Level 1, 2, and 3 financial instruments is provided in Note 5, 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 NAV. 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.

*Debt Securities*—Debt security investment funds are classified as Level 2 securities as pricing for underlying securities are determined by evaluating pricing data, such as broker quotes for similar securities, adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, if applicable.

*Collective trust funds*—Domestic and international mutual fund assets and debt security assets, including municipal debt and corporate credit securities, mortgage-backed securities, and asset back securities assets, are included in commingled trusts or separately managed accounts. The Company believes the redemption value of the collective trust funds are likely to be the fair value, which is represent by the net asset value as a practical expedient. The funds are valued at NAV as a practical expedient and are not classified 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 and are not classified in the fair value hierarchy.

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, 2020 and 2019. 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 | |
|---|---|---|---|---|---|---|
| | 2020 | 2019 | 2020 | 2019 | 2020 | 2019 |
| **Benefit obligation:** | | | | | | |
| As of January 1 | $ 905 | $ 811 | $ 71 | $ 72 | $ 26 | $ 24 |
| Service cost | 17 | 16 | 2 | 2 | — | — |
| Interest cost | 31 | 34 | 2 | 3 | 1 | 1 |
| Participants' contributions | — | — | — | 2 | — | — |
| Actuarial loss (gain) | 104 | 88 | 4 | 8 | 3 | 3 |
| Benefit payments | (44) | (42) | (4) | (6) | (2) | (2) |
| Administrative expenses | (3) | (2) | — | — | — | — |
| Plan amendment | — | — | 1 | (9) | — | — |
| Curtailment gain | — | — | — | (1) | — | — |
| As of December 31 | $ 1,010 | $ 905 | $ 76 | $ 71 | $ 28 | $ 26 |
| **Fair value of plan assets:** | | | | | | |
| As of January 1 | $ 695 | $ 546 | $ 34 | $ 30 | $ 17 | $ 16 |
| Actual return on plan assets | 105 | 131 | 2 | 5 | 1 | 1 |
| Company contributions | — | 62 | 3 | 3 | 3 | 2 |
| Participants' contributions | — | — | — | 2 | — | — |
| Benefit payments | (44) | (42) | (4) | (6) | (2) | (2) |
| Administrative expenses | (3) | (2) | — | — | — | — |
| As of December 31 | $ 753 | $ 695 | $ 35 | $ 34 | $ 19 | $ 17 |
| **Unfunded position as of December 31** | $ (257) | $ (210) | $ (41) | $ (37) | $ (9) | $ (9) |
| **Accumulated benefit plan obligation as of December 31** | $ 907 | $ 813 | N/A | N/A | $ 24 | $ 26 |
| **Classification in consolidated balance sheet:** | | | | | | |
| Noncurrent asset | $ — | $ — | $ — | $ — | $ 19 | $ 17 |
| Current liability | — | — | — | — | (2) | (2) |
| Noncurrent liability | (257) | (210) | (41) | (37) | (26) | (24) |
| Net liability | $ (257) | $ (210) | $ (41) | $ (37) | $ (9) | $ (9) |
| **Amounts included in comprehensive income:** | | | | | | |
| Net actuarial loss (gain) | $ 43 | $ (3) | $ 4 | $ 5 | $ 3 | $ 3 |
| Net prior service credit | 1 | — | — | (9) | — | — |
| Amortization of net actuarial loss | (17) | (10) | — | — | (1) | (1) |
| Amortization of prior service credit | — | — | 1 | — | — | — |
| | $ 27 | $ (13) | $ 5 | $ (4) | $ 2 | $ 2 |
| **Amounts included in AOCL:*** | | | | | | |
| Net actuarial loss (gain) | $ 239 | $ 213 | $ 5 | $ 1 | $ 15 | $ 13 |
| Prior service cost | 1 | — | (8) | (9) | — | — |
| | $ 240 | $ 213 | $ (3) | $ (8) | $ 15 | $ 13 |

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are classified as Regulatory assets or liabilities as future recoverability is expected from retail customers.

Significant actuarial gains (losses) experienced that resulted in changes in projected benefit obligation included the following:

- For the defined benefit pension plan, actuarial losses due to demographic experience, including assumption changes, were losses of $104 million and $88 million, and the changes between actual and expected return on plan assets were gains of $61 million and $94 million for the years ended December 31, 2020 and 2019, respectively.
- For the other postretirement benefits, actuarial losses due to demographic experience, including assumption changes, were losses of $5 million and $2 million, and the changes between actual and expected return on plan assets were gains of $1 million for each of the years ended December 31, 2020 and 2019, respectively.

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 | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 | 2020 | 2019 | 2018 |
| Service cost | $ 17 | $ 16 | $ 19 | $ 2 | $ 2 | $ 2 | $ — | $ — | $ — |
| Interest cost on benefit obligation | 31 | 34 | 32 | 2 | 3 | 3 | 1 | 1 | 1 |
| Expected return on plan assets | (44) | (40) | (42) | (2) | (2) | (1) | — | — | — |
| Amortization of prior service credit | — | — | — | (1) | — | — | — | — | — |
| Amortization of net actuarial loss | 17 | 10 | 17 | — | — | — | 1 | 1 | 1 |
| Curtailment gain | — | — | — | — | (2) | — | — | — | — |
| Net periodic benefit cost | $ 21 | $ 20 | $ 26 | $ 1 | $ 1 | $ 4 | $ 2 | $ 2 | $ 2 |

The portion of non-service costs attributable to expense related to the pension and other postretirement benefit plans, is classified as Miscellaneous income (expense), net within Other income on the Company's consolidated statements of income. Amounts related to the pension and other postretirement benefits are offset with the amortization of the corresponding regulatory asset.

The following assumptions were used in determining benefit obligations and net period benefit costs:

| | Defined Benefit Pension Plan | | Other Postretirement Benefits | | Non-Qualified Benefit Plans | |
|---|---|---|---|---|---|---|
| | 2020 | 2019 | 2020 | 2019 | 2020 | 2019 |
| **Assumptions used to determine benefit obligations:** | | | | | | |
| Discount rate | 2.64 % | 3.43 % | 2.22% - 2.92 % | 3.19% - 3.47 % | 2.64 % | 3.43 % |
| Rate of compensation increase | 3.65 % | 3.65 % | 4.58 % | 4.58 % | 4.10 % | N/A |
| **Assumptions used to determine net periodic benefit cost:** | | | | | | |
| Discount rate | 3.43 % | 4.25 % | 3.19% - 3.47 % | 3.11% - 4.26 % | 3.43 % | 3.43 % |
| Rate of compensation increase | 3.65 % | 3.65 % | 4.58 % | 4.58 % | 4.10 % | N/A |
| Long-term rate of return on plan assets | 7.00 % | 7.00 % | 5.02 % | 5.88 % | N/A | N/A |

As of December 31, 2020, there are no liabilities with sensitivity to health care cost trend rates.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets, or a 0.25% reduction in the discount rate, would have the effect of increasing the 2020 net periodic pension expense by approximately $2 million and $3 million, respectively.

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 | | | | | |
|---|---|---|---|---|---|---|
| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 - 2030 |
| Defined benefit pension plan | $ 45 | $ 45 | $ 46 | $ 47 | $ 47 | $ 243 |
| Other postretirement benefits | 5 | 5 | 5 | 6 | 5 | 19 |
| Non-qualified benefit plans | 2 | 2 | 3 | 2 | 2 | 11 |
| Total | $ 52 | $ 52 | $ 54 | $ 55 | $ 54 | $ 273 |

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.

### *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 to the 401(k) Plan 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 $26 million in 2020, $25 million in 2019, and $23 million in 2018.

## NOTE 12: INCOME TAXES

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Current: | | | |
| Federal | $ 6 | $ 9 | $ 12 |
| State and local | 17 | 12 | 22 |
| | 23 | 21 | 34 |
| Deferred: | | | |
| Federal | (22) | (2) | (15) |
| State and local | (1) | 8 | (2) |
| | (23) | 6 | (17) |
| Income tax expense | $ — | $ 27 | $ 17 |

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, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Federal statutory tax rate | 21.0 % | 21.0 % | 21.0 % |
| Federal tax credits(1) | (20.5) | (13.4) | (16.7) |
| State and local taxes, net of federal tax benefit(2) | 10.1 | 6.5 | 6.5 |
| Flow through depreciation and cost basis differences | (4.9) | 1.5 | 1.5 |
| Amortization of excess deferred income tax(3) | (4.7) | (3.7) | (4.1) |
| Other | (1.0) | (0.7) | (0.8) |
| Effective tax rate | — % | 11.2 % | 7.4 % |

(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 2030.

(2) In 2019, Oregon enacted HB 3427, which imposed a new gross receipts tax on companies with annual revenues in excess of $1 million and applies to tax years beginning on or after January 1, 2020. The legislation defines that the tax applies to commercial activities sourced in Oregon, less certain deductions. The resulting amount is taxed at 0.57%.

(3) The majority of excess deferred income taxes related to remeasurement under the TCJA is subject to IRS normalization rules and will be amortized over the remaining regulatory life of the assets using the average rate assumption method.

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

| | As of December 31, | |
|---|---|---|
| | 2020 | 2019 |
| Deferred income tax assets: | | |
| Employee benefits | $ 136 | $ 119 |
| Price risk management | 29 | 26 |
| Regulatory liabilities | 23 | 22 |
| Tax credits | 77 | 64 |
| Total deferred income tax assets | 265 | 231 |
| Deferred income tax liabilities: | | |
| Depreciation and amortization | 504 | 496 |
| Regulatory assets | 128 | 103 |
| Other | 7 | 10 |
| Total deferred income tax liabilities | 639 | 609 |
| Deferred income tax liability, net | $ 374 | $ 378 |

As of December 31, 2020, PGE has federal credit carryforwards of $77 million, consisting of PTCs, which will expire at various dates through 2040. PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2020 and 2019 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2020, and 2019, PGE had no material unrecognized tax benefits.

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

## NOTE 13: 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 or 1,500 shares (based on fair value on the purchase date), 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, 2020, there were 241,281 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, 2020, there were 2,462,263 shares available for future issuance pursuant to the DRIP.

## NOTE 14: 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. RSU activity is summarized in the following table:

| | Units | Weighted Average Grant Date Fair Value |
|---|---|---|
| Nonvested units as of December 31, 2017 | 399,376 | $ 37.98 |
| Granted | 198,864 | 37.99 |
| Forfeited | (8,556) | 39.73 |
| Vested | (160,771) | 36.77 |
| Nonvested units of December 31, 2018 | 428,913 | 38.43 |
| Granted | 210,555 | 49.06 |
| Forfeited | (9,041) | 41.68 |
| Vested | (167,037) | 37.52 |
| Nonvested units as of December 31, 2019 | 463,390 | 43.52 |
| Granted | 202,883 | 56.45 |
| Forfeited | (17,341) | 50.27 |
| Vested | (170,536) | 45.67 |
| Nonvested units as of December 31, 2020 | 478,396 | 48.00 |

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 2,737,180 shares remain available for future issuance as of December 31, 2020.

Outstanding RSUs provide for the payment of one Dividend Equivalent Right (DER) for each stock unit. Each DER represents an amount equal to dividends paid to shareholders on a share of PGE's common stock and vests on the same schedule as the related RSU. The DERs are settled in 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).

*Time-based RSUs* generally vest over a period of up to three years from 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 $1 million for the years ended December 31, 2020, 2019 and 2018.

*Performance-based RSUs* vest based on the extent to which performance goals are met at the end of a three-year performance period, subject to adjustment by the Compensation and Human Resources Committee of PGE's Board of Directors. The number of RSUs that may vest under grants awarded in 2018 is based on two equally-weighted metrics: i) actual return on equity relative to allowed return on equity; and ii) a relative total shareholder return (TSR) of PGE's common stock as compared to an index of peer companies during the performance period. Based on the attainment of the goals, the number of RSUs that vest can range from zero to 175% of the RSUs granted. The number of RSUs that may vest under grants awarded in 2019 and 2020 is based on three equally-weighted metrics: i) actual return on equity relative to allowed return on equity; ii) average EPS growth; and iii) power supply portfolio decarbonization—and relative TSR as a modifier to the total of the three equally-weighted metrics. Based on the attainment of the goals, the number of RSUs that vest can range from zero to 175% of the RSUs granted.

For return on equity, average EPS growth and carbon reduction metrics of the performance-based RSUs, fair value is measured based on the NYSE 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 with the following weighted average assumptions:

| | 2020 | 2019 | 2018 |
|---|---|---|---|
| Risk-free interest rate | 1.4 % | 2.5 % | 2.4 % |
| Expected term (in years) | 2.9 | 3.0 | 3.0 |
| Volatility | 13.5 % - 97.3 % | 14.8 % - 74.5 % | 14.7 % - 21.8 % |

There is no expected dividend yield used in the valuation, as it is assumed that all dividends distributed during the performance period are reinvested in the Company's underlying stock. 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 157.3%, 129.0%, and 69.0% of awarded performance-based RSUs for the respective 2020, 2019, and 2018 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $9 million for the year ended December 31, 2020, $7 million for 2019, and $4 million for 2018.

*Stock-based compensation,* included in Administrative and other expense in the consolidated statements of income, was $11 million for the year ended December 31, 2020, $9 million for 2019, and $5 million in 2018. Such amounts differ from those reported in the consolidated statements of shareholders' equity 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 consolidated statements 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 2020, 2019, and 2018.

As of December 31, 2020, unrecognized stock-based compensation expense was $13 million, which is expected to be recognized over a weighted average period of one to three years. No stock-based compensation costs have been capitalized.

## NOTE 15: EARNINGS PER SHARE

Basic earnings per share are computed based on the weighted average number of common shares outstanding during the year. Diluted earnings per share are computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the year using the treasury stock method. Potential common shares consist of: i) employee stock purchase plan shares; and ii) contingently issuable time-based and performance-based restricted stock units, along with associated DERs. Unvested performance-based restricted stock units and associated DERs are included in dilutive potential common shares only after the performance criteria have been met. Anti-dilutive stock awards are excluded from the calculation of diluted earnings per common share.

Net income attributable to PGE common shareholders is the same for both the basic and diluted earnings per share computations. The reconciliations of the denominators of the basic and diluted earnings per share computations are as follows (in thousands):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2020 | 2019 | 2018 |
| Weighted average common shares outstanding—basic | 89,485 | 89,353 | 89,215 |
| Dilutive potential common shares | 160 | 206 | 132 |
| Weighted average common shares outstanding—diluted | 89,645 | 89,559 | 89,347 |

## NOTE 16: COMMITMENTS AND GUARANTEES

### *Purchase Commitments*

As of December 31, 2020, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

| | Payments Due | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2021 | 2022 | 2023 | 2024 | 2025 | Thereafter | Total |
| Capital and other purchase commitments | $ 237 | $ 33 | $ 20 | $ 1 | $ 1 | $ 55 | $ 347 |
| Purchased power and fuel: | | | | | | | |
| Electricity purchases | 250 | 257 | 284 | 278 | 249 | 2,886 | 4,204 |
| Capacity contracts | 9 | 9 | 9 | 9 | 9 | — | 45 |
| Public utility districts | 21 | 19 | 18 | 17 | 17 | 39 | 131 |
| Natural gas | 57 | 42 | 37 | 43 | 43 | 578 | 800 |
| Coal and transportation | 27 | 27 | 27 | 27 | 27 | — | 135 |
| Total | $ 601 | $ 387 | $ 395 | $ 375 | $ 346 | $ 3,558 | $ 5,662 |

*Capital and other purchase commitments*—Certain commitments have been made for 2021 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 2052, 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 Hydroelectric Projects, and
- Douglas County PUD for the Wells Hydroelectric Project.

Under the Grant County 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. Under the Douglas County agreement, the Company is required to make 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 County's 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, 2020 | PGE's Average Share as of December 31, 2020 | | Contract Expiration | Total PGE Contract Costs | | |
|---|---|---|---|---|---|---|---|
| | | Output | Capacity (in MW) | | 2020 | 2019 | 2018 |
| Priest Rapids and Wanapum | $ 1,880 | 8.6 % | 163 | 2052 | $ 25 | $ 21 | $ 17 |
| Wells | 572 | 16.6 | 94 | 2028 | 23 | 16 | 11 |

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.

*Coal and transportation*—PGE had coal and related rail transportation agreements with take-or-pay provisions related to the Boardman coal-fired generation plant (Boardman) that expired in December 2020 in conjunction with the cessation of coal fired generation at Boardman. The Company has a coal agreement with take-or-pay provisions related to Colstrip Units 3 and 4 coal-fired generation plant (Colstrip) that expires in December 2025.

***Guarantees***

PGE enters into financial agreements, and purchase and sale agreements involving physical delivery of, both power and natural gas 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, 2020, 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 consolidated balance sheets with respect to these indemnities.

## NOTE 17: LEASES

PGE determines if an arrangement is a lease at inception and whether the arrangement is classified as an operating or finance lease. At commencement of the lease, PGE records a right-of-use (ROU) asset and lease liability in the consolidated balance sheets based on the present value of lease payments over the term of the arrangement. ROU assets represent the right to use an underlying asset for the lease term and lease liabilities represent PGE's obligation to make lease payments arising from the lease. If the implicit rate is not readily determinable in the contract, PGE uses its incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. Contract terms may include options to extend or terminate the lease, and, when the

Company deems it is reasonably certain that PGE will exercise that option, it is included in the ROU asset and lease liability.

Operating leases reflect lease expense on a straight-line basis, while finance leases result in the separate presentation of interest expense on the lease liability and amortization expense of the ROU asset. Any material differences between expense recognition and timing of payments is deferred as a regulatory asset or liability in order to match what is being recovered in customer prices for ratemaking purposes.

PGE does not record leases with a term of 12-months or less in the consolidated balance sheets. Total short-term lease costs as of December 31, 2020 are immaterial. PGE has lease agreements with lease and non-lease components, which are accounted for separately.

The Company's leases relate primarily to the use of land, support facilities, gas storage, and power purchase agreements that rely on identified plant. Variable payments are generally related to gas storage and power purchase agreements for components dependent upon variable factors, such as energy production and property taxes, and are not included in the determination of the present value of lease payments.

The components of lease cost were as follows (in millions):

| | 2020 | 2019 |
|---|---|---|
| **Operating lease cost** | $ 8 | $ 7 |
| **Finance lease cost:** | | |
| Amortization of right-of-use assets | $ 5 | $ 3 |
| Interest on lease liabilities | 10 | 6 |
| Total finance lease cost | $ 15 | $ 9 |
| **Variable lease cost** | $ 12 | $ 19 |

Supplemental information related to amounts and presentation of leases in the consolidated balance sheets is presented below (in millions):

| | Balance Sheet Classification | December 31, 2020 | December 31, 2019 |
|---|---|---|---|
| **Operating Leases:** | | | |
| Operating lease right-of-use assets | Other noncurrent assets | $ 44 | $ 51 |
| Current liabilities | Accrued expenses and other current liabilities | $ 8 | $ 8 |
| Noncurrent liabilities | Other noncurrent liabilities | 36 | 43 |
| Total operating lease liabilities* | | $ 44 | $ 51 |
| **Finance Leases:** | | | |
| Finance lease right-of-use assets | Electric utility plant, net | $ 145 | $ 150 |
| Current liabilities | Current portion of finance lease obligations | $ 16 | $ 16 |
| Noncurrent liabilities | Finance lease obligations, net of current portion | 129 | 135 |
| Total finance lease liabilities | | $ 145 | $ 151 |

*Included in lease liabilities are $25 million and $32 million related to power purchase agreements for the years ended December 31, 2020 and 2019, respectively.

Lease term and discount rates were as follows:

| | December 31, 2020 | December 31, 2019 |
|---|---|---|
| **Weighted Average Remaining Lease Term (in years)** | | |
| Operating leases | 26 | 24 |
| Finance leases | 28 | 29 |
| **Weighted Average Discount Rate** | | |
| Operating leases | 3.6 % | 3.5 % |
| Finance leases | 7.3 % | 7.3 % |

PGE’s gas storage finance lease contains five 10-year renewal periods which have not been included in the finance lease obligation.

As of December 31, 2020, maturities of lease liabilities were as follows (in millions):

| | Operating Leases | Finance Leases |
|---|---|---|
| 2021 | $ 8 | $ 16 |
| 2022 | 8 | 16 |
| 2023 | 8 | 14 |
| 2024 | 7 | 14 |
| 2025 | 1 | 13 |
| Thereafter | 45 | 222 |
| Total lease payments | 77 | 295 |
| Less imputed interest | (33) | (150) |
| Total | $ 44 | $ 145 |

Supplemental cash flow information related to leases was as follows (in millions):

| | December 31, 2020 | December 31, 2019 |
|---|---|---|
| **Cash paid for amounts included in the measurement of lease liabilities:** | | |
| Operating cash flows from operating leases | $ 8 | $ 7 |
| Operating cash flows from finance leases | 10 | 5 |
| Financing cash flows from finance leases | 6 | 4 |
| **Right-of-use assets obtained in leasing arrangements:** | | |
| Operating leases | $ — | $ 56 |
| Finance leases | — | 154 |

As of December 31, 2020, PGE has an additional operating lease for an energy storage agreement that has not yet commenced with an estimated present value of future lease payments of $30 million. This lease is expected to commence in 2022 with a lease term of 20 years.

## NOTE 18: JOINTLY-OWNED PLANT

As of December 31, 2020, PGE had the following investments in jointly-owned plant (dollars in millions):

| | PGE Share | In-service Date | Plant In-service | Accumulated Depreciation* | Construction Work In Progress |
|---|---|---|---|---|---|
| Colstrip | 20.00 % | 1986 | $ 566 | $ 387 | $ 7 |
| Pelton/Round Butte | 66.67 % | 1958 / 1964 | 283 | 82 | 7 |
| Total | | | $ 849 | $ 469 | $ 14 |

* Excludes AROs and accumulated asset retirement removal costs.

Under the respective joint operating agreements for the generating facilities, each participating owner is responsible for financing its share of capital and operating expenses. 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 consolidated statements of income.

The Company operated, and continues to have a 90% ownership interest in, Boardman, which ceased coal-fired operations during the fourth quarter of 2020. The Company has begun the initial steps toward decommissioning the facility. As of December 31, 2020, PGE's ARO liability for its 90% share of the decommissioning costs was $44 million.

## NOTE 19: 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 consolidated 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.

### *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 2017. The ROD outlined the EPA's selected remediation plan for clean-up of the Portland Harbor site, which has an undiscounted 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. 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. Stakeholders have raised concerns that EPA's cost estimates are understated. 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.

A small group of PRPs performed pre-remedial design sampling to update baseline data and submitted the data in an updated evaluation report to the EPA for review. The evaluation report concluded that the conditions of the Portland Harbor Superfund site have improved substantially over the past ten years. In response, the EPA indicated that while it would use the data to inform implementation of the ROD, the EPA's conclusions remained materially unchanged. With the completion of pre-remedial design sampling, Portland Harbor is now in the remedial design phase, which consists of additional technical information and data collection to be used to design the expected remedial actions. Certain PRPs, not including PGE, have entered into consent agreements to perform remedial design and the EPA has indicated it will take the initial lead to perform remedial design on the remaining areas. The EPA announced on February 12, 2021 that 100% of Portland Harbor is under an active engineering design phase.

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 that are integral to the determination of such an allocation percentage, remedial design, a final allocation methodology, and data with regard to property specific activities and history of ownership of sites within Portland Harbor that will inform the precise boundaries for clean-up. It is probable that PGE will share in a portion of the costs related to Portland Harbor. However, based on the above facts and remaining uncertainties, PGE does not currently have sufficient information to reasonably estimate the amount, or range, of its potential liability or determine an allocation percentage that represents PGE's portion of the liability to clean-up Portland Harbor, although such costs could be material to PGE's financial position.

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 consist of the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, the state of Oregon, the Confederated Tribes of the Grand Ronde Community of Oregon, the Confederated Tribes of Siletz Indians, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS), and the Nez Perce Tribe.

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.

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 by the OPUC 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 if necessary, through customer prices. The mechanism established annual prudency reviews of environmental expenditures and third-party proceeds. Annual expenditures in excess of $6 million, excluding expenses related to contingent liabilities, are subject to an annual earnings test and would be ineligible for recovery to the extent PGE's actual regulated return on equity exceeds its return on equity as authorized by the OPUC in PGE's most recent general rate case. Under the PHERA mechanism in 2020, PGE incurred and deferred $6 million related to defense costs, net of an immaterial estimated refund as a result of PGE overearning in the regulated earnings test for this deferral. 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 plans to seek recovery of any costs resulting from the EPA's determination of liability for Portland Harbor through application of the PHERA. At this time, PGE is not recovering any Portland Harbor cost from the PHERA through customer prices.

***Trojan Investment Recovery Class Actions***

In 1993, PGE closed 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 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 (Circuit Court); and ii) Morgan v. Portland General Electric Company, Marion County Circuit Court. The class action lawsuits sought 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, 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 lifted the abatement on the class action proceedings and heard oral argument on the Company's motion for Summary Judgment. In 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. The plaintiffs subsequently appealed the Circuit Court dismissal to the Court of Appeals for the state of Oregon.

In November 2019, the Court of Appeals issued an opinion that affirmed the Circuit Court dismissal. On December 30, 2019, the plaintiffs filed a motion for reconsideration, which the Court of Appeals denied on February 4, 2020.

On April 7, 2020, the Plaintiffs filed a petition with the OSC requesting review and reversal of the Court of Appeals opinion. On July 16, 2020, the OSC issued an order that denied the petition for review.

***Deschutes River Alliance Clean Water Act Claims***

In August 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 March and April 2018, DRA and PGE filed cross-motions for summary judgment and PGE and CTWS, which co-own the Project, filed separate motions to dismiss. CTWS initially appeared as a friend of the court, but subsequently was found to be a necessary party to the lawsuit and joined as a defendant.

In August 2018, the U.S. District Court of the District of Oregon (District Court) 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 District Court 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.

In October 2018, DRA filed an appeal, and PGE and CTWS filed cross-appeals, to the Ninth Circuit Court of Appeals. The appeals are fully briefed and the parties await a schedule for oral argument.

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

***Shareholder Lawsuits***

During September and October, 2020, three putative class action complaints were filed in U.S. District Court for the District of Oregon against PGE and certain of its officers, captioned *Hessel v. Portland General Electric Co.*, No. 20-cv-01523 (*"Hessel"*), *Cannataro v. Portland General Electric Co.*, No. 3:20-cv-01583 (*"Cannataro"*), and *Public Employees' Retirement System of Mississippi v. Portland General Electric Co.*, No. 20-cv-01786 (*"PERS of Mississippi"*). Two of these actions were filed on behalf of purported purchasers of PGE stock between April 24, 2020, and August 24, 2020; a third action was filed on behalf of purported purchasers of PGE stock between February 13, 2020, and August 24, 2020.

During the fourth quarter of 2020, the plaintiff in *Hessel* voluntarily dismissed his case and the court consolidated *Cannataro* and *PERS of Mississippi* into a single case captioned *In re Portland General Electric Company Securities Litigation* and appointed Public Employees' Retirement System of Mississippi lead plaintiff ("Lead Plaintiff"). On January 11, 2021, Lead Plaintiff filed an amended complaint asserting causes of action arising under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 for alleged misstatements and omissions regarding, among other things, PGE’s alleged lack of sufficient internal controls and risks associated with PGE's trading activity in wholesale electric markets, purportedly on behalf of purchasers of PGE stock between February 13, 2020, and August 24, 2020. The complaint demands a jury trial and seeks compensatory damages of an unspecified amount and reimbursement of plaintiffs' costs, and attorneys' and expert fees.

The Company intends to vigorously defend against the lawsuit. Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible loss.

***Putative Shareholder Derivative Lawsuit***

On January 26, 2021, a putative shareholder derivative lawsuit, was filed in Multnomah County Circuit Court, Oregon, captioned *Shimberg v. Pope*, No. 21- cv-02957, against one current and one former PGE executive and several members of the Company's Board of Directors (collectively, the "Individual Defendants") and naming the Company as a nominal defendant only. The plaintiff asserts a claim for alleged breaches of fiduciary duties purportedly on behalf of PGE, arising from the energy trading losses the Company previously announced in August 2020. The plaintiff alleges that the Individual Defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and seeks damages to be awarded to the Company of not less than $10 million, equitable relief to remedy the alleged breaches of fiduciary duty, and an award of plaintiff’s attorneys’ fees and costs.

Since the lawsuit is in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible 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.

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

## ITEM 9A. CONTROLS AND PROCEDURES.

(a) Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and the Chief Financial Officer, has evaluated the effectiveness of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) as of the end of the period covered by this report pursuant to Rule 13a-15(b) under the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, the Company’s disclosure controls and procedures are effective.

(b) Management’s Annual Report on Internal Control over Financial Reporting

The Company’s management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act). The Company’s internal control over financial reporting is a process designed by, or under the supervision of, the Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company’s financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company’s internal control over financial reporting as of the end of the period covered by this report pursuant to Rule 13a-15(c) under the Exchange Act. Management’s assessment was based on the framework established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2020, the Company’s internal control over financial reporting is effective.

The Company’s internal control over financial reporting, as of December 31, 2020, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company’s consolidated financial statements, as stated in their report included in Item 8.—“Financial Statements and Supplementary Data,” which expresses an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting, as of December 31, 2020.

(c) Changes in Internal Control over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting during the fourth quarter of 2020 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

## ITEM 9B. OTHER INFORMATION.

None.

# PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Certain information required by Item 10 is incorporated herein by reference to the relevant information under the captions "Corporate Governance" and "Item 1: Election of Directors" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the United States Securities and Exchange Commission (SEC) in connection with the Annual Meeting of Shareholders scheduled to be held on April 28, 2021. Information regarding executive officers of Portland General Electric Company may be found in Part I, Item 1. Business of this Annual Report on Form 10-K.

## ITEM 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is incorporated herein by reference to the relevant information under the captions "Corporate Governance—Director Compensation," "Corporate Governance—Compensation Committee Interlocks," "Compensation and Human Resources Committee Report," "Compensation Discussion and Analysis," and "Executive Compensation Tables" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 28, 2021.

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by Item 12 is incorporated herein by reference to the relevant information under the captions "Security Ownership of Certain Beneficial Owners, Directors and Executive Officers," in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 28, 2021.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is incorporated herein by reference to the relevant information under the caption "Corporate Governance" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 28, 2021.

## ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 is incorporated herein by reference to the relevant information under the captions "Principal Accountant Fees and Services" and "Pre-Approval Policy for Independent Auditor Services" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on April 28, 2021.

# PART IV

## ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) Financial Statements and Schedules

The financial statements are set forth under Item 8 of this Annual Report on Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibit Listing

| Exhibit Number | Description |
|---|---|
| **(3)** | **Articles of Incorporation and Bylaws** |
| 3.1* | Third Amended and Restated Articles of Incorporation of Portland General Electric Company (Form 8-K filed May 9, 2014, Exhibit 3.1). |
| 3.2* | Eleventh Amended and Restated Bylaws of Portland General Electric Company (Form 10-K filed February 15, 2019, Exhibit 3.2). |
| **(4)** | **Instruments defining the rights of security holders, including indentures** |
| 4.1* | Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 (Form 8, Amendment No. 1 dated June 14, 1965) (File No. 001-05532-99). |
| 4.2* | Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 001-05532-99). |
| 4.3* | Sixty-second Supplemental Indenture dated April 1, 2009 (Form 8-K filed April 16, 2009, Exhibit 4.1) (File No. 001-05532-99). |
| 4.4* | Seventy-third Supplemental Indenture dated August 1, 2017, between the Company and Wells Fargo Bank, National Association, as Trustee (Form 8-K filed August 3, 2017, Exhibit 4.1). |
| 4.5* | Seventy-fifth Supplemental Indenture, dated April 1, 2019, between the Company and Wells Fargo Bank, National Association, as trustee (Form 8-K filed April 15, 2019, Exhibit 4.1). |
| 4.6* | Description of Securities (Form 10-K filed February 15, 2019, Exhibit 4.6). |
| **(10)** | **Material Contracts** |
| 10.1* | Amended and Restated Credit Agreement dated March 6, 2015 between Portland General Electric Company and Wells Fargo Bank, National Association, as Administrative Agent, Bank of America, N.A., Barclays Bank PLC, JPMorgan Chase Bank, N.A. and U.S. Bank National Association (Form 10-Q filed April 27, 2015, Exhibit 10.1). |
| 10.2* | First Amendment to Credit Agreement, dated February 21, 2017 among Portland General Electric Company, Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders (Form 10-K filed February 16, 2018, Exhibit 10.2). |
| 10.3* | Second Amendment to Credit Agreement, dated as of January 16, 2019 among Portland General Electric Company, Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders (Form 10-K filed February 15, 2019, Exhibit 10.3). |
| 10.4* | Consent Agreement, dated December 6, 2017 among Portland General Electric Company, Lenders, and Wells Fargo Bank, National Association, as administrative agent for the Lenders (Form 10-K filed February 16, 2018, Exhibit 10.3). |
| 10.5* | Portland General Electric Company Severance Pay Plan for Executive Employees, as amended and restated effective February 14, 2017 (Form 10-K filed February 17, 2017, Exhibit 10.2). + |
| 10.6* | Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2) (File No. 001-05532-99). + |
| 10.7* | Portland General Electric Company 2005 Management Deferred Compensation Plan dated January 1, 2005 (Form 10-K filed March 11, 2005, Exhibit 10.18) (File No. 001-05532-99). + |
| 10.8* | Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1) (File No. 001-05532-99). + |

| Exhibit Number | Description |
|---|---|
| 10.9* | Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2) (File No. 001-05532-99). + |
| 10.10* | Portland General Electric Company Umbrella Trust for Management dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.4) (File No. 001-05532-99). + |
| 10.11* | Portland General Electric Company Stock Incentive Plan, As Amended and Restated Effective February 13, 2018. (Form 10-Q filed April 27, 2018, Exhibit 10.1) (File No. 001-055532-99). + |
| 10.12* | Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1) (File No. 001-05532-99). + |
| 10.13* | Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 8-K filed December 24, 2009, Exhibit 10.1) (File No. 001-05532-99). + |
| 10.14* | Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters for Officers and Key Employees (Form 8-K filed February 19, 2010, Exhibit 10.1) (File No. 001-05532-99). + |
| 10.15* | Form of Directors' Restricted Stock Unit Agreement (Form 10-K filed February 15, 2019, Exhibit 10.18).+ |
| 10.16* | Form of Officers' and Key Employees' Performance Stock Unit Agreement (Form 10-K filed February 15, 2019, Exhibit 10.19).+ |
| 10.17* | Form of Officers' and Key Employees' Restricted Stock Unit Agreement (Form 10-K filed February 15, 2019, Exhibit 10.20).+ |
| 10.18* | Separation Agreement dated September 27, 2019 by and between William Nicholson and Portland General Electric Company. (Form 10-K filed February 15, 2019, Exhibit 10.21).+ |
| 10.19 | Portland General Electric Company Amended and Restated Incentive Compensation Clawback and Cancellation Policy.+ |
| 10.20 | Portland General Electric Company Annual Cash Incentive Plan, as Amended and Restated February 17, 2021.+ |
| 10.21 | Form of Officers' and Key Employees' Performance Stock Unit Agreement.+ |
| 10.22 | Form of Officers' and Key Employees' Restricted Stock Unit Agreement.+ |
| **(23)** | **Consents of Experts and Counsel** |
| 23.1 | Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP. |
| **(31)** | **Rule 13a-14(a)/15d-14(a) Certifications** |
| 31.1 | Certification of Chief Executive Officer. |
| 31.2 | Certification of Chief Financial Officer. |
| **(32)** | **Section 1350 Certifications** |
| 32.1 | Certifications of Chief Executive Officer and Chief Financial Officer. |
| **(101)** | **Interactive Data File** |
| 101.INS | XBRL Instance Document. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document. |
| 101.SCH | XBRL Taxonomy Extension Schema Document. |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document. |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document. |
| 101.LAB | XBRL Taxonomy Extension Label Linkbase Document. |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document. |
| 104 | Cover page information from Portland General Electric Company's Annual Report on Form 10-K filed February 14, 2020, formatted in iXBRL (Inline Extensible Business Reporting Language). |

* Incorporated by reference as indicated.

\+ Indicates a management contract or compensatory plan or arrangement.

Certain instruments defining the rights of holders of other long-term debt of PGE are omitted pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K because the total amount of securities authorized under each such omitted instrument does not exceed 10% of the total consolidated assets of the Company and its subsidiaries. PGE hereby agrees to furnish a copy of any such instrument to the SEC upon request.

Upon written request to Investor Relations, Portland General Electric Company, 121 S.W. Salmon Street, Portland, Oregon 97204, the Company will furnish shareholders with a copy of any Exhibit upon payment of reasonable fees for reproduction costs incurred in furnishing requested Exhibits.

**ITEM 16. FORM 10-K SUMMARY.**

None.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on February 18, 2021.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ MARIA M. POPE

**Maria M. Pope**
*President and Chief Executive Officer*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 18, 2021.

| Signature | Title |
|---|---|
| /s/ MARIA M. POPE<br>**Maria M. Pope** | *President, Chief Executive Officer, and Director*<br>(principal executive officer) |
| /s/ JAMES A. AJELLO<br>**James A. Ajello** | *Senior Vice President of Finance, Chief Financial Officer, and Treasurer*<br>(principal financial and accounting officer) |
| /s/ JOHN W. BALLANTINE<br>**John W. Ballantine** | *Director* |
| /s/ RODNEY L. BROWN, JR.<br>**Rodney L. Brown, Jr.** | *Director* |
| /s/ JACK E. DAVIS<br>**Jack E. Davis** | *Director* |
| /s/ KIRBY A. DYESS<br>**Kirby A. Dyess** | *Director* |
| /s/ MARK B. GANZ<br>**Mark B. Ganz** | *Director* |
| /s/ MARIE OH HUBER<br>**Marie Oh Huber** | *Director* |
| /s/ KATHRYN J. JACKSON<br>**Kathryn J. Jackson** | *Director* |
| /s/ MICHAEL A. LEWIS<br>**Michael A. Lewis** | *Director* |
| /s/ MICHAEL H. MILLEGAN<br>**Michael H. Millegan** | *Director* |
| /s/ NEIL J. NELSON<br>**Neil J. Nelson** | *Director* |
| /s/ M. LEE PELTON<br>**M. Lee Pelton** | *Director* |
| /s/ CHARLES W. SHIVERY<br>**Charles W. Shivery** | *Director* |
| /s/ JAMES P. TORGERSON<br>**James P. Torgerson** | *Director* |

**EXHIBIT 23.1**

## CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-232976 on Form S-3 and Registration Statements Nos. 333-135726, 333-142694, and 333-158059 on Forms S-8 of our report dated February 18, 2021, relating to the consolidated financial statements of Portland General Electric Company and subsidiaries, and the effectiveness of Portland General Electric Company’s internal control over financial reporting, appearing in this Annual Report on Form 10-K of Portland General Electric Company for the year ended December 31, 2020.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 18, 2021

**EXHIBIT 31.1**

# CERTIFICATION

I, Maria M. Pope, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2021

/s/ MARIA M. POPE

Maria M. Pope

*President and*
*Chief Executive Officer*

**EXHIBIT 31.2**

**CERTIFICATION**

I, James A. Ajello, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2021

/s/ JAMES A. AJELLO
James A. Ajello
*Senior Vice President of Finance, Chief Financial Officer, and Treasurer*

**EXHIBIT 32.1**

**CERTIFICATIONS PURSUANT TO
18 U.S.C. SECTION 1350, AS ADOPTED
PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

We, Maria M. Pope, President and Chief Executive Officer, and James A. Ajello, Senior Vice President of Finance, Chief Financial Officer and Treasurer, of Portland General Electric Company (the “Company”), hereby certify that the Company’s Annual Report on Form 10-K for the year ended December 31, 2020, as filed with the Securities and Exchange Commission on February 19, 2021 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the “Report”), fully complies with the requirements of that section.

We further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ MARIA M. POPE
Maria M. Pope
*President and*
*Chief Executive Officer*

Date: February 18, 2021

/s/ JAMES A. AJELLO
James A. Ajello
*Senior Vice President of Finance,*
*Chief Financial Officer and*
*Treasurer*

Date: February 18, 2021

# Corporate Information

## BOARD OF DIRECTORS

**Jack E. Davis**
Chair of the Board of Directors,
Portland General Electric
Retired Chief Executive Officer,
Arizona Public Service

**Maria M. Pope**
President and Chief Executive Officer,
Portland General Electric

**John W. Ballantine**
Retired Executive Vice President and
Chief Risk Management Officer,
First Chicago NBD Corporation

**Rodney L. Brown Jr.**
Founding Partner,
Cascadia Law Group PLLC

**Kirby A. Dyess**
Principal,
Austin Capital Management LLC

**Mark B. Ganz**
Retired President and
Chief Executive Officer,
Cambia Health Solutions Inc.

**Marie Oh Huber**
Senior Vice President,
Chief Legal Officer, General Counsel
and Secretary, eBay Inc.

**Kathryn J. Jackson**
Director of Energy and Technology
Consulting, KeySource Inc.

**Michael A. Lewis**
Retired Interim President,
Pacific Gas and Electric Company

**Michael H. Millegan**
Founder and Chief Executive Officer,
Millegan Advisory Group 3 LLC

**Neil J. Nelson**
Retired President,
Siltronic Corporation

**M. Lee Pelton**
President, Emerson College

**Charles W. Shivery**
Retired Chairman, President
and Chief Executive Officer,
Northeast Utilities

**James P. Torgerson**
Retired Chief Executive Officer,
AVANGRID Inc.

## CORPORATE OFFICERS

**Maria M. Pope**
President and Chief Executive Officer

**James A. Ajello**
Senior Vice President, Finance,
Chief Financial Officer and Treasurer

**Larry N. Bekkedahl**
Vice President, Grid Architecture,
Integration and Systems Operations

**Bradley Y. Jenkins**
Vice President, Utility Operations

**Lisa A. Kaner**
Vice President, General Counsel
and Corporate Compliance Officer

**John T. Kochavatr**
Vice President,
Information Technology and
Chief Information Officer

**John C. McFarland**
Vice President,
Chief Customer Officer

**Anne F. Mersereau**
Vice President, Human Resources,
Diversity, Equity and Inclusion

**W. David Robertson**
Vice President, Public Affairs

**Brett M. Sims**
Vice President, Strategy,
Regulation & Energy Supply

## INVESTOR INFORMATION

**Corporate Headquarters**
Portland General Electric Company
121 SW Salmon St.
Portland, OR 97204
503-464-8000
investors.portlandgeneral.com

**Transfer Agent**
American Stock Transfer &
Trust Company LLC
6201 15th Ave.
Brooklyn, NY 11219
866-621-2788

**Independent Auditors**
Deloitte & Touche LLP
U.S. Bancorp Tower
111 SW 5th Ave.
Suite 3900
Portland, OR 97204
503-222-1341

**Form 10-K**
A copy of the Company's
2020 Annual Report on Form 10-K
will be furnished, without charge,
upon written request made to:
Jardon Jaramillo
Senior Director of Treasury, Investor
Relations and Risk Management
121 SW Salmon St.
1WTC0501
Portland, OR 97204

You may also obtain a copy of the Form 10-K by calling Investor Relations at 503-464-8586 or by downloading a copy from investors.portlandgeneral.com.

**Market Information**
Portland General Electric Company stock trades on the New York Stock Exchange under the ticker symbol POR.

To vote online, visit investors.portlandgeneral.com.

# 2020 Highlights

We're making progress toward our vision of a clean energy future and are committed to adopting environmental, social and governance (ESG) best practices to ensure the sustainability of our company for the benefit of customers, investors and other stakeholders. We're also committed to transparent reporting on important ESG issues that matter to our stakeholders. In 2020, we enhanced our annual ESG disclosures, using frameworks developed by the Sustainability Accounting Standards Board and the Edison Electric Institute. These reports are available online at **investors.portlandgeneral.com.**

Wind energy like the turbines at Biglow Canyon (pictured here) and the Wheatridge Renewable Energy Facility are part of our long-term strategy for a clean energy future.

# Sustainable Environment

Net Zero greenhouse gas emissions by 2040 goal established, with an interim goal of 80% reduction by 2030.

End of coal-fired power generation in Oregon, thanks to the historic closure of the Boardman Coal Plant 20 years ahead of schedule.

120 new wind turbines operating at the Wheatridge Renewable Energy Facility, the nation's first large-scale facility to combine wind, solar and battery storage. The 300 megawatt (MW) wind farm is a joint project of PGE and NextEra Energy Resources LLC.

160 additional MW of clean hydropower acquired through a partnership with Douglas County Public Utility District. The agreement is part of PGE's 2019 Integrated Resource Plan, which also calls for acquiring cost-effective energy efficiency and integrating distributed flexibility.

25% of our customers purchase 100% green energy, making our Renewable Energy Program the No. 1 program in the U.S. for the 11th straight year. Customers in PGE's Smart Grid Test Bed are also helping to create a virtual power plant with no greenhouse gas emissions by installing energy storage batteries at their homes.

18 large businesses and municipalities are reducing their carbon footprints and reaching their climate goals by participating in PGE's Green Future Impact program, purchasing a large bulk of their energy needs from regional renewable energy projects made possible by their participation.

$215M investment in an Integrated Operations Center with enhanced technology and resiliency against seismic, cybersecurity and physical security risks, to centralize key operations and functions.

$2.3M in grants to expand equitable access to electric transportation through the PGE Drive Change Fund. Another $2 million in grants were contributed through the PGE Electric School Bus Fund to help public school districts in our service area purchase Oregon's first six electric buses. Funding for both programs comes from the sale of Oregon Clean Fuels Program credits, which PGE aggregates on behalf of customers who charge their electric vehicles at home.

60% target set for electrification of PGE's fleet vehicles by 2030.

14 new fish passage, wildlife habitat and water quality improvement projects initiated across Central Oregon through $5.5 million in grants provided by PGE and the Confederated Tribes of Warm Springs. PGE is also restoring wetland habitat along 74 acres of the Willamette River.

# Caring for Communities & Our Employees

**$5.6M** contributed by PGE, employees, retirees and the PGE Foundation to support local schools and nonprofits. This includes $1 million in support to help address food insecurity during the COVID-19 pandemic.

**18,200** hours employees safely volunteered in their community despite increased restrictions for gathering due to COVID-19.

**First** K-12 open-source climate literacy curriculum, developed in partnership with Portland Public Schools. It's part of PGE Project Zero, which educates youth about creating a clean energy future. Project Zero also provides green job internships for young adults—especially those from BIPOC communities.

**100%** rating on the Human Rights Campaign Foundation's Corporate Equality Index and inclusion in the Bloomberg Gender-Equality Index. These ratings demonstrate our companywide commitment to equality for women, the LGBTQ community and people from all backgrounds through policies, workforce development and community engagement.

# 2020 Governance

**Annual** election of all board directors by majority vote of the shareholders supported by an active board refreshment program, with two new leading energy experts Jim Torgerson and Michael Lewis added in 2020.

**50%** of board directors are diverse, based on gender and race, including our female Chief Executive Officer.

**Second** year executive incentive awards were tied to our strategic imperatives, including metrics related to our carbon reduction goals and smart grid investments.

**More than half** of the PGE executive team's compensation takes the form of incentive awards, including cash and equity awards, designed to further our clean energy strategy.

**Enhanced** risk reporting with energy trading activity to ensure greater visibility into portfolio risk.

**$129M** of additional investment for system health and resiliency focused on reducing outages, wildfires and other disaster mitigation, as well as cybersecurity and physical security. This includes investments in our $215 million, multiyear Integrated Operations Center construction to further elevate PGE's system resiliency and advance our smart grid objectives.

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PGE