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

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) Portland General Electric Company	Year/Period of Report End of: 2022/ Q4

FERC FORM NO. 1 (REV. 02-04)

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, Licensees, and Others 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 Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

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.)

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 [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF 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. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

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/general-information-0/electric-industry-forms.

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, 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.

X. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

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 by 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 shall 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 (ED. 03-07)

FERC FORM NO. 1 REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER	
IDENTIFICATION	
01 Exact Legal Name of Respondent Portland General Electric Company	02 Year/ Period of Report End of: 2022/ Q4
03 Previous Name and Date of Change (If name changed during year) /	
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 121 SW Salmon Street, Portland, Oregon, 97204	

05 Name of Contact Person Christopher Liddle	06 Title of Contact Person Controller & Asst. Treasurer
07 Address of Contact Person (Street, City, State, Zip Code) 121 SW Salmon Street, Portland, Oregon, 97204	

08 Telephone of Contact Person, Including Area Code (503) 464-7458	09 This Report is An Original / A Resubmission (1) An Original (2) A Resubmission	10 Date of Report (Mo, Da, Yr) 04/14/2023

Annual Corporate Officer Certification

The undersigned officer certifies that:

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

01 Name James A. Ajello	03 Signature James A. Ajello	04 Date Signed (Mo, Da, Yr) 04/14/2023
02 Title Senior VP of Finance, CFO & Treasurer, Corporate Compliance Officer		

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.

FERC FORM No. 1 (REV. 02-04)

Name of Respondent:	This report is:	Date of Report:	Year/Period of Report
Portland General Electric Company	(1) An Original (2) A Resubmission	04/14/2023	End of: 2022/ Q4

LIST OF SCHEDULES (Electric Utility)

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

16	**Electric Plant in Service**	204	
17	**Electric Plant Leased to Others**	213	none
18	**Electric Plant Held for Future Use**	214	
19	**Construction Work in Progress-Electric**	216	
20	**Accumulated Provision for Depreciation of Electric Utility Plant**	219	
21	**Investment of Subsidiary Companies**	224	
22	**Materials and Supplies**	227	
23	**Allowances**	228	
24	**Extraordinary Property Losses**	230a	none
25	**Unrecovered Plant and Regulatory Study Costs**	230b	
26	**Transmission Service and Generation Interconnection Study Costs**	231	
27	**Other Regulatory Assets**	232	
28	**Miscellaneous Deferred Debits**	233	
29	**Accumulated Deferred Income Taxes**	234	
30	**Capital Stock**	250	
31	**Other Paid-in Capital**	253	
32	**Capital Stock Expense**	254b	
33	**Long-Term Debt**	256	
34	**Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax**	261	
35	**Taxes Accrued, Prepaid and Charged During the Year**	262	
36	**Accumulated Deferred Investment Tax Credits**	266	none
37	**Other Deferred Credits**	269	
38	**Accumulated Deferred Income Taxes-Accelerated Amortization Property**	272	none
39	**Accumulated Deferred Income Taxes-Other Property**	274	
40	**Accumulated Deferred Income Taxes-Other**	276	
41	**Other Regulatory Liabilities**	278	
42	**Electric Operating Revenues**	300	
43	**Regional Transmission Service Revenues (Account 457.1)**	302	none
44	**Sales of Electricity by Rate Schedules**	304	
45	**Sales for Resale**	310	
46	**Electric Operation and Maintenance Expenses**	320	
47	**Purchased Power**	326	
48	**Transmission of Electricity for Others**	328	
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 (Account 403, 404, 405)**	336	
53	**Regulatory Commission Expenses**	350	
54	**Research, Development and Demonstration Activities**	352	
55	**Distribution of Salaries and Wages**	354	
56	**Common Utility Plant and Expenses**	356	none

FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

GENERAL INFORMATION

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

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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.

-

State of Incorporation: OR

Date of Incorporation: 1930-07-25

Incorporated Under Special Law:

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.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

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

(2) No

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	121 SW Salmon Street Corporation	Company has purchased the headquarters complex in Portland, Oregon and leases the complex to the Respondent	100%	
2	World Trade Center Northwest Corporation (A wholly-owned subsidiary of 121 SW Salmon Street Corporation)	Company is the holder of the World Trade Center Franchise	100%	
3	Salmon Springs Hospitality Group, Inc.	Company provides food catering services	100%	
4	121 SW Salmon Street LLC			
5	Portland Renewable Resource Company LLC			

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	President and Chief Executive Officer	Maria M. Pope	[a]1,065,067		
2	Senior Vice President of Finance, Chief Financial Officer and Treasurer	James A. Ajello	639,517		
3	Vice President, General Counsel and Corporate Compliance Officer	Lisa A. Kaner	238,629		2022-07-01
4	Vice President Strategy Regulation and Energy Supply	Brett Sims	370,521		
5	Vice President, Public Affairs	W. David Robertson	200,905		2022-08-01
6	Vice President, Chief Customer Officer	John McFarland	145,601		2022-05-06
7	Vice President, Utility Operations	Bradley Y. Jenkins	440,242		

8	Senior Vice President, Advanced Energy Delivery	Larry N. Bekkedahl	471,795		
9	Vice President, Information Technology and Chief Information Officer	John Kochavatr	455,188		
10	Vice President, Human Resources, Diversity, Equity and Inclusion	Anne E. Mersereau	370,449		
11	Vice President, Public Policy, Government Affairs and Communiations	Nicholas G. Blosser	153,846	2022-07-25	
12	Vice President, General Counsel	Angelica Espinosa	433,299	2022-03-18	

FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: OfficerSalary

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

FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Rodney L. Brown, Jr.	Portland, Oregon		
2	Jack E. Davis Chair of the Board	Portland, Oregon		
3	(a) Kirby A. Dyess	Portland, Oregon		
4	Mark B. Ganz	Portland, Oregon		
5	Kathryn J. Jackson	Portland, Oregon		
6	(b) Neil J. Nelson	Portland, Oregon		
7	M. Lee Pelton	Portland, Oregon		
8	Maria M. Pope President and Chief Executive Officer	Portland, Oregon		
9	Marie Oh Huber	Portland, Oregon		
10	Michael H. Millegan	Portland, Oregon		
11	Michael L. Lewis	Portland, Oregon		
12	James P. Torgerson	Portland, Oregon		
13	Dawn L. Farrell	Portland, Oregon		
14	(c) Patricia S. Pineda	Portland, Oregon		

FERC FORM No. 1 (ED. 12-95)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: NameAndTitleOfDirector
Term ended April 22, 2022
(b) Concept: NameAndTitleOfDirector
Term ended April 22, 2022.
(c) Concept: NameAndTitleOfDirector
Appointed to the Board October 1, 2022

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 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.

1. None

2. None

3. None

4. None

5. None

6. Pursuant to PGE's application, the Federal Energy Regulatory Commission (FERC), on January 20, 2022, issued an order in Docket No. ES22-18-000 that authorizes the Company to issue up to $900 million of short-term debt through February 6, 2024. 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.

In September 2022, PGE amended its existing revolving credit facility. As of December 31, 2022, PGE had a $650 million unsecured revolving credit facility scheduled to expire in September 2027. The Company has the ability to expand the revolving credit facility to $750 million, if needed. 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, 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 the Company'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, 2022, PGE was in compliance with this covenant with a 56.9% debt to total capital ratio. In addition, the credit facility offers the potential for adjustments to interest rate margins and fees based on PGE's achievement of certain annual sustainability-linked metrics related to its non-emitting generation capacity and the percentage of management comprised of women and employees who identify as black, indigenous, and people of color. The Company believes these potential adjustments will have an immaterial impact on PGE's results of operations.

Under the revolving credit facility, as of December 31, 2022, 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 $650 million.
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 in order to allow coverage for the potential need to repay commercial paper that may be outstanding at the time. As of December 31, 2022, 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.

In addition, PGE has three letter of credit facilities that provide 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 $97 million were outstanding, as of December 31, 2022. Letters of credit issued are not reflected on the Company's Comparative Balance Sheet.

On November 30, 2022, PGE entered into a Bond Purchase Agreement related to the sale of $200 million in FMBs. The bonds consist of:

- a series, due in 2029, in the amount of $100 million that will bear interest at an annual rate of 5.47%; and
- a series, due in 2033, in the amount of $100 million that will bear interest at an annual rate of 5.56%.

The 2029 and 2033 series were issued in 2022 and funded in full on November 30, 2022 and January 13, 2023, respectively.

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.

On October 21, 2022, PGE obtained a 366-day term loan from lenders in the aggregate principal of $260 million under a 366-Day Bridge Credit Agreement. The term loan bears interest for the relevant interest period at the Term Secured Overnight Financing Rate (SOFR) plus Term SOFR Adjustment Rate of 10 basis points and Applicable Margin of 87.5 basis points. The interest rate is subject to adjustment pursuant to the terms of the loan. The loan is prepayable, in whole or in part, without penalty, at any time. The credit agreement expires on October 22, 2023, with any outstanding balance due and payable on such date. The term loan is classified as Other Long Term Debt on PGE's Comparative Balance Sheet.

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, 2022, 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:

Securities Case

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* (the "Securities Action") 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 Amended Complaint"). The Amended Complaint demands a jury trial and seeks compensatory damages of an unspecified amount and reimbursement of plaintiffs' costs, and attorneys' and expert fees. On March 12, 2021, the defendants filed a motion to dismiss the Amended Complaint.

On July 11, 2021, the parties entered into a Stipulation of Settlement (the "Agreement") to fully resolve the Securities Action. The Agreement, which is subject to Court approval, provides for a settlement payment of $6.75 million in exchange for the complete dismissal with prejudice and a release of all claims against the defendants in connection with the Securities Action, without any admission of fault or wrongdoing by the defendants. On July 16, 2021, the Lead Plaintiff filed an application for Court approval of the settlement. In an order dated August 10, 2021, the Court granted preliminary approval of the settlement, stayed all proceedings in the action except with respect to settlement, and scheduled a final settlement approval hearing for March 11, 2022. The settlement payment was paid by the Company's insurance provider under its insurance policy. In light of the Agreement, the Court removed the hearing on the defendants' pending motion to dismiss from the calendar. At the hearing on March 11, 2022, the Court approved the settlement, with an opinion to follow; on March 22, 2022, the Court entered an Opinion and Order Approving Settlement, Attorney's Fees, and Expenses; and on March 28, 2022, the Court entered a final Judgment and Order of Dismissal with Prejudice.

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, (the "*Shimberg* Action") against one current and one former PGE executive and certain members and former members of the Company's Board of Directors 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 defendants made material misstatements and omissions and allowed the Company to operate with inadequate internal controls. The complaint demands a jury trial and sought 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. On June 1, 2021, the plaintiff filed an unopposed motion to consolidate this lawsuit with the *Ashabraner* Action (described below), which the Court granted in an order dated July 27, 2021.

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, (the "*JS Halberstam* Action") against one current and one former PGE executive and certain current and former 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 demanded 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.

On April 7, 2021, a putative shareholder derivative lawsuit was filed in Multnomah County Circuit Court, Oregon, captioned, *Ashabraner v. Pope*, 21-cv-13698 the "*Ashabraner* Action"), against one current and one former PGE executive and certain and former 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. On July 27, 2021, the Court issued an order consolidating the *Ashabraner* Action with the *Shimberg* Action.

On May 21, 2021, a putative shareholder derivative lawsuit was filed in the U.S. District Court for the District of Oregon, Portland Division captioned *Berning v. Pope*, No. 3:21-cv-00783-SI, (the "*Berning Action*"; collectively with the *Shimberg*, *JS Halberstam*, and *Ashabraner* Actions, the "Derivative Actions"), against one current and one former PGE executive and certain current and former members of the Company's Board of Directors and named the Company as a nominal defendant only. The plaintiff asserted claims 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 also asserted a claim against the two executives for contribution and indemnity based on alleged violations of Sections 10(b) and 21D of the Exchange Act. The complaint demanded a jury trial and sought multiple forms of relief, including, among other things: a declaration that defendants breached and/or aided and abetted the breach of their fiduciary duties to PGE; an order directing PGE to reform and improve its corporate governance and internal procedures; restitution; and an award of attorneys' fees, expenses, and costs.

On December 17, 2021, the parties to the Derivative Actions entered into a Memorandum of Understanding to settle the Derivative Actions subject to court approval and other terms (the "MOU"). After the parties entered into the MOU, the Court in the *Shimberg* and *Ashabraner* Actions granted an order to abate the proceedings until June 21, 2022. On December 17, 2021, the parties in the JS Halberstam Action filed a motion to stay the proceedings pending submission and court review of the settlement contemplated in the MOU.
On February 11, 2022, the parties to the Derivative Actions entered into a Stipulation of Settlement memorializing the terms of the non-monetary settlement, subject to Court approval, as set forth in the MOU. Under the Stipulation of Settlement, the parties to the *JS Halberstam* Action agreed to stay the proceedings in the Derivative Actions pending Court approval of the settlement. In addition, the Stipulation of Settlement provided that defendants would not oppose or object to a request by plaintiffs' counsel for fees and expenses up to $750,000, which was subject to Court approval. Upon final approval of the Court, such fees and expenses were paid by the Company's insurance provider under its insurance policy. On February 15, 2022, the plaintiff in the *JS Halberstam* Action filed a motion for preliminary approval of the settlement.
On March 28, 2022, the United States District Court for the District of Oregon entered an order preliminarily approving the settlement and the form and content of the notice to shareholders and set a final hearing for May 9, 2022, in the *JS Halberstam* Action. On April 18, 2022, the plaintiff in the *JS Halberstam* Action filed a motion for final approval of the settlement and fee and expense award. On May 9, 2022 the Court issued orders that granted final judgment approval of the settlement.

Governmental Investigations

In March, April and May 2021, the Division of Enforcement of the Commodity Futures Trading Commission (the "CFTC"), the Division of Enforcement of the Securities and Exchange Commission (SEC), and the Division of Enforcement of the FERC, respectively, informed the Company they are conducting investigations arising out of the energy trading losses the Company previously announced in August 2020. The Company is cooperating with the CFTC, the SEC, and the FERC. Management cannot at this time predict the eventual scope or outcome of these matters.

Colstrip-Related Litigation

The Company has a 20% ownership interest in Colstrip, which is operated by one of the co-owners, Talen Montana, LLC (Talen). On May 10, 2022, Talen's parent company, Talen Energy Supply, LLC, filed for chapter 11 bankruptcy protection, although Colstrip continues to operate and generate electricity for PGE customers and others. Various business disagreements have arisen amongst the co-owners regarding interpretation of the Ownership and Operation (O&O) Agreement and other matters. An arbitration process has been initiated to address such business disagreements and has resulted in several legal proceedings. These legal proceedings, as well as other matters related to Colstrip, are summarized below.

*Arbitration*On March 12, 2021, co-owner NorthWestern Corporation (NorthWestern) initiated arbitration against all other co-owners of Colstrip to determine whether co-owners representing 55% or more of the ownership shares can vote to close one or both units of Colstrip, or, alternatively, whether unanimous consent is required. The O&O Agreement among the parties states that any dispute shall be submitted for resolution to a single arbitrator with appropriate expertise. This arbitration process was initially stayed as a result of the bankruptcy filing of Talen's parent company, but that stay was lifted in August 2022, by a voluntary stipulation, described below. The arbitration has once again been stayed through June 16, 2023, by agreement of the parties. PGE cannot predict the ultimate outcome of the arbitration process.

*Petition to compel arbitration*In April 2021, Avista Corporation, Puget Sound Energy Inc., PacifiCorp, and PGE (the Petitioners) petitioned in Spokane County Superior Court, Washington, Case No. 21201000-32, against NorthWestern and Talen to compel the arbitration initiated by NorthWestern that is described above. In May 2021, Talen removed the case to Federal Court (Eastern District of Washington Case No. 2:21-cv-00163-RMP). Following a hearing in July 2021, Talen's motion to transfer the case to the U.S. District Court for the District of Montana was granted. This matter is stayed, because of the bankruptcy filing of Talen's parent company. The voluntary stipulation described below (see *"Challenge to constitutionality of Montana Senate Bills 265 and 266 (MSB 265 and MSB 266)"*) did not lift the stay on this court action.

*Challenge to constitutionality of Montana Senate Bills 265 and 266 (MSB 265 and MSB 266)*On May 4, 2021, the Petitioners filed a claim against NorthWestern and Talen in U.S. District Court - Montana, Billings Division, Case No. 1:21-cv-00047-SPW-KLD, based on the passage of MSB 265, which attempted to void contractual arbitration provisions within the O&O Agreement if they do not provide for three arbitrators or provide for venue outside of the county where the plant is located. The passage of MSB 265 was supported by Defendants and purported to void the O&O Agreement among all parties, which provides for one arbitrator and venue in Spokane, Washington. The Petitioners allege that MSB 265 violated the contracts clause of the U.S. Constitution and the Montana Constitution, and is preempted by the Federal Arbitration Act (FAA). The Petitioners sought declaratory relief that MSB 265 was unconstitutional as applied to the O&O Agreement and the FAA preempted the enforcement of MSB 265.

Petitioners filed a First Amended Complaint on May 19, 2021, adding the Attorney General of Montana (Montana AG) as defendant and challenging the constitutionality of MSB 266, which purportedly gives the Montana AG authority to penalize and restrain any co-owner of Colstrip who takes steps to shut-down the plant without unanimous consent, and authority to penalize any co-owner who fails or refuses to pay the costs to maintain the plant. The Court held a hearing on August 6, 2021 and on October 13, 2021, the Court issued an order that granted the Petitioners' Motion for Preliminary Injunction, enjoining the Montana AG from enforcing MSB 266 against them.

On August 17, 2021, the Petitioners filed for partial summary judgment on their claim to declare MSB 265 preempted by the FAA and unconstitutional. On October 29, 2021, the Petitioners filed a motion for partial summary judgment on their claim to declare MSB 266 unconstitutional and unenforceable. A decision on this matter had been stayed as a result of the bankruptcy filing of Talen's parent company, but the stay was lifted by a voluntary stipulation filed by Petitioners, Talen, and NorthWestern, and ordered by the bankruptcy court on August 25, 2022. On September 29, 2022, the Magistrate Judge issued Findings and Recommendations, which were adopted in full by the Court on October 19, 2022, granting both of the Petitioners' motions for summary judgment regarding the constitutionality of MSB 265 and MSB 266 by finding that MSB 266 was unconstitutional, and MSB 265 was unconstitutional and in the alternative preempted by the FAA.

*Complaint to implement MSB 265*On May 4, 2021, Talen filed a complaint against the Petitioners and NorthWestern, in the Thirteenth Judicial District Court in the State of Montana, as an attempt to implement Montana laws when determining the language of the O&O agreement based on the recent enactment of MSB 265. The case was subsequently removed to the U.S. District Court - Montana, Billings Division, Case No. 1:21-cv-00058-SPW-TJC. This matter is stayed, because of the bankruptcy filing of Talen's parent company.

*Richard Burnett; Colstrip Properties Inc., et al v. Talen Montana, LLC; PGE, et al*In December 2020, the original claim was filed in the Montana Sixteenth Judicial District Court, Rosebud County, Cause No. CV-20-58. The plaintiffs allege they have suffered adverse effects from the defendants' coal dust. In August 2021, the claim was amended to add PGE as a defendant. Plaintiffs are seeking economic damages, costs and disbursements, punitive damages, attorneys' fees, and an injunction prohibiting defendants from allowing coal dust to blow onto plaintiffs' properties, as determined by the Court. The Court set trial to begin September 26, 2023. This matter was stayed as a result of the bankruptcy filing of Talen's parent company. On September 23, 2022, by stipulation by the parties and order of the Court, the stay was modified to allow for some limited discovery by the parties in this matter. Pursuant to a stipulation by the parties, litigation has resumed and the parties are working through discovery issues.

Since these lawsuits (except for the challenge to constitutionality of MSB 265 and MSB 266) are in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible losses.

10. None

11. (Reserved)

12. None

13. Changes in Officers:
Angelica Espinosa was appointed Vice President, General Counsel effective March 18, 2022.
John C. McFarland, Vice President, Chief Customer Officer, resigned effective May 6, 2022.
Lisa A. Kaner, Vice President, General Counsel and Corporate Compliance Officer retired effective July 1, 2022.
Nicholas G. Blosser was appointed Vice President, Public Policy, Government Affairs and Communications effective July 25, 2022.
W. David Robertson, Vice President, Public Affairs, retired effective August 1, 2022.

Changes in Directors:

The number of directors on the Board decreased from thirteen to eleven effective as of the 2022 annual shareholder's meeting held on April 22, 2022, at which time, Kirby A. Dyess and Neil J. Nelson retired from the Board in accordance with the Company's director retirement age policy.
On September 27, 2022, the Board of Directors voted to appoint Patricia S. Pineda to serve as a Director of the Company, and the number of Directors on the Board increased from eleven to twelve, effective October 1, 2022.

14. None

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	12,403,927,120	11,855,629,261
3	Construction Work in Progress (107)	200	479,229,849	317,489,515
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		12,883,156,969	12,173,118,776
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	5,495,106,410	5,168,097,757

6	Net Utility Plant (Enter Total of line 4 less 5)		7,388,050,559	7,005,021,019
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	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	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)		7,388,050,559	7,005,021,019
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		2,870,226	2,595,247
19	(Less) Accum. Prov. for Depr. and Amort. (122)		465,486	467,810
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224	83,892,347	83,200,892
23	Noncurrent Portion of Allowances	228	0	0
24	Other Investments (124)		5,923,767	4,850,418
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		80,794,848	96,398,039
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		73,435,140	34,946,317
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		246,450,842	221,523,103
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		15,666,550	8,267,481
36	Special Deposits (132-134)		116,528,103	37,141,298
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		150,000,001	44,000,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		219,473,279	181,230,082
41	Other Accounts Receivable (143)		58,776,357	56,123,221
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		12,085,787	26,237,603
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		1,351,058	1,286,504
45	Fuel Stock (151)	227	29,151,034	25,459,349
46	Fuel Stock Expenses Undistributed (152)	227	1,378	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0

48	Plant Materials and Operating Supplies (154)	227	60,023,704	48,295,804
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202/227	0	0
52	Allowances (158.1 and 158.2)	228	3,023,770	1,528,000
53	(Less) Noncurrent Portion of Allowances	228	0	0
54	Stores Expense Undistributed (163)	227	2,754,586	2,270,648
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)		80,855,866	71,979,456
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)		131,856,462	117,683,800
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		386,616,225	137,169,781
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		73,435,140	34,946,317
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)		1,170,557,446	671,251,504
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		12,510,845	13,045,696
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	132,510,020	90,148,743
72	Other Regulatory Assets (182.3)	232	434,088,731	500,623,391
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,980,265	1,027,290
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)		0	0
77	Temporary Facilities (185)		24,702	0
78	Miscellaneous Deferred Debits (186)	233	9,736,583	10,937,917
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352	0	0
81	Unamortized Loss on Reaquired Debt (189)		17,340,512	18,929,465
82	Accumulated Deferred Income Taxes (190)	234	640,683,198	611,265,205
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,248,874,856	1,245,977,707
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		10,053,933,703	9,143,773,333

FERC FORM No. 1 (REV. 12-03)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

	(2) A Resubmission		

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	1,253,363,919	1,245,720,283
3	Preferred Stock Issued (204)	250	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	18,789,718	18,789,718
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	1,535,343,048	1,471,363,440
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	6,352,686	5,661,231
13	(Less) Reaquired Capital Stock (217)	250	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(3,965,243)	(9,929,713)
16	Total Proprietary Capital (lines 2 through 15)		2,786,770,596	2,708,491,427
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	3,398,800,000	3,298,800,000
19	(Less) Reaquired Bonds (222)	256	0	0
20	Advances from Associated Companies (223)	256	0	0
21	Other Long-Term Debt (224)	256	260,000,000	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		329,866	354,262
24	Total Long-Term Debt (lines 18 through 23)		3,658,470,134	3,298,445,738
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		337,658,448	294,466,454
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		7,019,752	7,232,587
29	Accumulated Provision for Pensions and Benefits (228.3)		264,684,842	311,391,348
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		10,245,694	23,697,796
32	Long-Term Portion of Derivative Instrument Liabilities		75,471,084	90,195,814
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		289,128,195	269,591,828
35	Total Other Noncurrent Liabilities (lines 26 through 34)		984,208,015	996,575,827
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		552,847,660	353,434,290

39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		15,025,014	13,650,173
41	Customer Deposits (235)		154,738,250	72,906,806
42	Taxes Accrued (236)	262	12,258,338	25,933,908
43	Interest Accrued (237)		30,682,106	29,267,150
44	Dividends Declared (238)		42,454,026	40,144,573
45	Matured Long-Term Debt (239)		0	0
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		18,743,334	22,565,242
48	Miscellaneous Current and Accrued Liabilities (242)		32,229,226	33,121,754
49	Obligations Under Capital Leases-Current (243)		26,983,721	24,209,640
50	Derivative Instrument Liabilities (244)		193,376,878	136,966,656
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		75,471,084	90,195,814
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)		1,003,867,469	662,004,378
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266	0	0
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	28,268,513	19,581,112
60	Other Regulatory Liabilities (254)	278	511,529,098	433,439,910
61	Unamortized Gain on Reaquired Debt (257)		2,013	10,065
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		841,673,575	834,236,978
64	Accum. Deferred Income Taxes-Other (283)		239,144,290	190,987,898
65	Total Deferred Credits (lines 56 through 64)		1,620,617,489	1,478,255,963
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		10,053,933,703	9,143,773,333

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in 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.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
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 purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders 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.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	2,702,424,185	2,415,154,366			2,702,424,185	2,415,154,366	0			
3	Operating Expenses											
4	Operation Expenses (401)	320	1,536,397,416	1,335,310,689			1,536,397,416	1,335,310,689	0			
5	Maintenance Expenses (402)	320	203,629,987	165,907,236			203,629,987	165,907,236	0			
6	Depreciation Expense (403)	336	335,206,965	318,796,594			335,206,965	318,796,594	0			
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	3,555,122	2,813,130			3,555,122	2,813,130	0			
8	Amort. & Depl. of Utility Plant (404-405)	336	60,100,949	57,981,551			60,100,949	57,981,551	0			
9	Amort. of Utility Plant Acq. Adj. (406)	336	0	0			0	0	0			
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		283,290	1,900,000			283,290	1,900,000	0			
11	Amort. of Conversion Expenses (407.2)		0	0			0	0	0			
12	Regulatory Debits (407.3)		23,096,438	42,205,195			23,096,438	42,205,195	0			
13	(Less) Regulatory Credits (407.4)		15,271,896	17,083,227			15,271,896	17,083,227	0			
14	Taxes Other Than Income Taxes (408.1)	262	154,021,039	143,889,438			154,021,039	143,889,438	0			
15	Income Taxes - Federal (409.1)	262	9,567,596	7,528,447			9,567,596	7,528,447	0			
16	Income Taxes - Other (409.1)	262	23,960,867	15,676,517			23,960,867	15,676,517	0			
17	Provision for Deferred Income Taxes (410.1)	234, 272	346,448,410	391,473,121			346,448,410	391,473,121	0			
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	342,334,727	391,287,302			342,334,727	391,287,302	0			
19	Investment Tax Credit Adj. - Net (411.4)	266	0	0			0	0	0			
20	(Less) Gains from Disp. of Utility Plant (411.6)		605,776	14,621,896			605,776	14,621,896	0			
21	Losses from Disp. of Utility Plant (411.7)		0	0			0	0	0			
22	(Less) Gains from Disposition of Allowances (411.8)		0	0			0	0	0			
23	Losses from Disposition of Allowances (411.9)		0	0			0	0	0			
24	Accretion Expense (411.10)		2,935,076	3,197,046			2,935,076	3,197,046	0			
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,340,990,756	2,063,686,539			2,340,990,756	2,063,686,539	0	0	0	0
27	Net Util Oper Inc (Enter Tot line 2 less 25)		361,433,429	351,467,827			361,433,429	351,467,827	0	0	0	0
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)		4,040	0								
33	Revenues From Nonutility Operations (417)		3,412,801	2,707,194								
34	(Less) Expenses of Nonutility Operations (417.1)		5,086,681	4,606,580								
35	Nonoperating Rental Income (418)		383,537	512,365								
36	Equity in Earnings of Subsidiary Companies (418.1)	119	691,455	1,113,932								
37	Interest and Dividend Income (419)		950,598	356,132								
38	Allowance for Other Funds Used During Construction (419.1)		13,599,123	16,515,804								
39	Miscellaneous Nonoperating Income (421)		10,402,354	8,011,165								
40	Gain on Disposition of Property (421.1)		24,765	229,709								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		24,373,912	24,839,721								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		0	60,005								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		2,266,554	2,213,410								
46	Life Insurance (426.2)		4,228,435	(3,063,217)								
47	Penalties (426.3)		733	151,133								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,273,149	1,385,189								
49	Other Deductions (426.5)		549,573	4,910,313								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		8,318,444	5,656,833								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	365,294	332,094								
53	Income Taxes-Federal (409.2)	262	(908,375)	(4,336,194)								
54	Income Taxes-Other (409.2)	262	(386,463)	(1,849,003)								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	5,809,155	6,678,363								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	3,717,411	1,482,208								
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)		1,162,200	(656,948)								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		14,893,268	19,839,836								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		136,366,647	127,313,142								
63	Amort. of Debt Disc. and Expense (428)		1,192,613	1,286,222								

64	Amortization of Loss on Reaquired Debt (428.1)		1,594,761	1,594,762								
65	(Less) Amort. of Premium on Debt-Credit (429)		0	0								
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		8,052	8,052								
67	Interest on Debt to Assoc. Companies (430)		0	0								
68	Other Interest Expense (431)		5,692,958	4,223,453								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,376,075	8,492,618								
70	Net Interest Charges (Total of lines 62 thru 69)		137,462,852	125,916,909								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		238,863,845	245,390,754								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)		0	0								
76	Income Taxes-Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)		0	0								
78	Net Income (Total of line 71 and 77)		238,863,845	245,390,754								

FERC FORM No. 1 (REV. 02-04)

Page 114-117

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, 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 for 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 for 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, attach them at page 122.

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		1,467,510,647	1,384,306,520
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1				
4.2	Reclassification of stranded tax effects due to Tax Reform			
4.3				
4.4				

4.5				
4.6				
4.7				
4.8				
4.9				
4.10				
4.11				
9	TOTAL Credits to Retained Earnings (Acct. 439)			0
10	Adjustments to Retained Earnings Debit			
10.1	Adjustments to Retained Earnings Debit. The amount of $13,212,451 represents the repurchase of common stock in February and March 2022.	131	(13,212,451)	(8,667,694)
10.2				
10.3				
10.4				
10.5				
10.6				
10.7				
10.8				
10.9				
10.10				
10.11				
15	TOTAL Debits to Retained Earnings (Acct. 439)		(13,212,451)	(8,667,694)
16	Balance Transferred from Income (Account 433 less Account 418.1)		238,172,389	244,276,822
17	Appropriations of Retained Earnings (Acct. 436)			
17.1				
17.2				
17.3				
17.4				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
23.1				
23.2				
23.3				
23.4				
23.5				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Dividends Declared-Common Stock (Acct. 438)	238	(160,980,330)	(152,405,001)
30.2				
30.3				
30.4				
30.5				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(160,980,330)	(152,405,001)

37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,531,490,255	1,467,510,647
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
39.1				
39.2				
39.3				
39.4				
39.5				
39.6				
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	3,852,793
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,852,793	3,852,793
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,535,343,048	1,471,363,440
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		5,661,231	4,547,299
50	Equity in Earnings for Year (Credit) (Account 418.1)		691,455	1,113,932
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1				
53	Balance-End of Year (Total lines 49 thru 52)		6,352,686	5,661,231

FERC FORM No. 1 (REV. 02-04)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	238,863,845	245,390,754
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	398,863,036	379,591,275
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Debt Discount	2,779,322	2,872,932
5.2	Amortization of Unrecovered Plant	283,290	1,900,000
5.3	Net Price Risk Management Activities	(193,036,223)	(106,031,370)
8	Deferred Income Taxes (Net)	6,205,427	5,381,975

9	Investment Tax Credit Adjustment (Net)	0	0
10	Net (Increase) Decrease in Receivables	(69,285,365)	(59,098,176)
11	Net (Increase) Decrease in Inventory	(17,400,671)	(5,744,282)
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	162,468,899	55,566,699
14	Net (Increase) Decrease in Other Regulatory Assets	186,268,489	(46,086,999)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(27,791,356)	71,818,085
16	(Less) Allowance for Other Funds Used During Construction	13,599,123	16,515,804
17	(Less) Undistributed Earnings from Subsidiary Companies	691,455	1,113,932
18	Other (provide details in footnote):		
18.1	Other: Margin and Customer Deposits	2,444,639	28,504,164
18.2	Other: Operating	[(a)]7,855,448	[(d)](21,980,311)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	684,228,202	534,455,010
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(794,015,596)	(660,956,523)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	(274,979)	(233,451)
30	(Less) Allowance for Other Funds Used During Construction	(13,599,123)	(16,515,804)
31	Other (provide details in footnote):		
31.1	Other Capital Activities	[(b)](10,434,410)	[(e)](16,664,422)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(791,125,862)	(661,338,592)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	0	0
39	Investments in and Advances to Assoc. and Subsidiary Companies	0	0
40	Contributions and Advances from Assoc. and Subsidiary Companies	0	0
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
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	Other (provide details in footnote):		
53.1	Sale of Property	13,444,593	4,389,395
53.2	Other Investments	3,635,238	(8,734,211)
53.3	Purchases of Trojan Decommissioning Securities	(3,061,326)	(10,481,917)

53.4	Sales of Trojan Decommissioning Securities	2,852,491	12,157,140
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(774,254,866)	(664,008,185)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	360,000,000	400,000,000
62	Preferred Stock		
63	Common Stock	(4,862,840)	(1,202,389)
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)	0	(150,000,000)
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	355,137,160	248,797,611
72	Payments for Retirement of:		
73	Long-term Debt (b)	0	(160,000,000)
74	Preferred Stock		
75	Common Stock	(17,995,125)	(12,018,111)
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):	[c]25,007,873	0
76.2	Debt Issue Costs	(994,911)	(1,775,839)
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(157,729,263)	(149,965,295)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	203,425,734	(74,961,634)
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	113,399,070	(204,514,809)
88	Cash and Cash Equivalents at Beginning of Period	52,267,481	256,782,290
90	Cash and Cash Equivalents at End of Period	165,666,551	52,267,481

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Amounts relate primarily to prepayments and stock compensation expense.

(b) Concept: OtherConstructionAndAcquisitionOfPlantInvestmentActivities

Amounts primarily relate to cost of removal activity.

(c) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Amounts relate to proceeds from the Pelton/Round Butte failed sale-leaseback transaction.

(d) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Amounts relate primarily to prepayments

(e) Concept: OtherConstructionAndAcquisitionOfPlantInvestmentActivities

Amounts relate primarily to cost of removal activity

This report is:

Name of Respondent: Portland General Electric Company	(1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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.

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)	$ 8,267,481	$ 15,666,550
Working Funds (135)		
Temporary Cash Investments (136)	44,000,000	150,000,001
	$ 52,267,481	$ 165,666,551
	2021	**2022**
Cash paid during the year:		
Interest	$ 128,560,129	$ 135,072,765
Allowance for borrowed funds used during construction	(8,492,618)	(7,376,075)
	$ 120,067,511	$ 127,696,690
Income taxes	$ 15,664,968	$ 36,621,275
Non-cash investing and financing activities:		
Accrued capital additions	$ 87,062,845	$ 111,199,583
Accrued dividends payable	$ 40,144,573	$ 42,454,026
Preliminary engineering transferred to Construction work in progress	$ 1,441,391	$ 969,351

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 (State). 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 continues to develop products and service offerings for the benefit of retail and wholesale 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 owns unregulated, non-utility real estate comprised primarily of PGE's corporate headquarters. 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. PGE's allocated service area includes 51 incorporated cities. As of December 31, 2022, PGE served approximately 926 thousand retail customers with a service area population of approximately 1.9 million.

As of December 31, 2022, PGE had 2,873 employees in its workforce, with 673 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. One agreement covers 610 employees and expires March 2025, and the other covers 63 employees and expires August 2027. PGE also utilizes independent contractors and temporary personnel to supplement its workforce.

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 Statement of Income be classified differently than that required by GAAP. These include the requirement that all gains and losses on non-physical settlements of electricity derivative activities be recorded on a gross basis rather than on a net basis, as required by GAAP (for additional information, see Note 5 - Risk Management). In addition, certain items that are considered to be non-operating in nature are recorded in Other Income Deductions in the FERC Statement of Income but are recorded within Operating Expenses in financial statements prepared in accordance with GAAP.

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

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosures of gain or loss contingencies, as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ materially from those estimates.

Subsequent Events

PGE has evaluated the impact of events occurring after December 31, 2022 up to February 16, 2023, the date that the Company's U.S. GAAP financial statements were issued, and has updated such evaluation for disclosure purposes through April 14, 2023. These financial statements include all necessary adjustments and disclosures resulting from such evaluations.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Temporary Cash Investments

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 $150 million as of December 31, 2022 and $44 million as of December 31, 2021 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, 2021, and much of 2022, the Company took steps to support customers during the COVID-19 pandemic, including suspending late fees and developing time payment arrangements. COVID-19 protections ended in September 2022.

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 and unbilled revenues. For more information on PGE's Accumulated Provision for Uncollectible Accounts receivable and unbilled revenues see "*Customer Accounts Receivable, Net"* in Note 3, Comparative Balance Sheet Components. A portion of PGE's Provision for Uncollectible Accounts and unbilled revenues is deferred as a regulatory asset, for more information see *"COVID-19"* in Note 6, Regulatory Assets and Liabilities.

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 2022 or 2021.

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 $116 million as of December 31, 2022 and $37 million as of December 31, 2021. Letters of credit provided as collateral are not recorded on the Company's Comparative Balance Sheet and were $33 million and $18 million as of December 31, 2022 and 2021, 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 (AFUDC). 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 AFUDC, 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. In 2020, the FERC issued a waiver that allowed jurisdictional utilities to apply an alternative AFUDC calculation formula that excluded the actual outstanding short-term debt balance and replaced it with the simple average of the actual 2019 short-term debt balance. PGE adopted the waiver in the second quarter of 2020. The purpose of the waiver, which ultimately expired March 31, 2022, was 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.

AFUDC is capitalized as part of the cost of plant and credited to the Statement of Income. The average rate used by PGE was 6.5% in 2022 and 6.7% in 2021. AFUDC from borrowed funds, reflected as a reduction to Interest Charges was $7 million in 2022 and $8 million in 2021. AFUDC from equity funds, included in Other Income, was $14 million in 2022 and $17 million in 2021.

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 3.4% in both 2022 and 2021. 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 2021, PGE completed a depreciation study based on 2019 data, with an order received from the OPUC in December 2021 authorizing new depreciation rates effective May 9, 2022.

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 2025 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	30
Transmission	61
Distribution	51
General	16

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 Provision for Depreciation, Amortization, and Depletion. 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 $499 million and $446 million as of December 31, 2022 and 2021, respectively, with amortization expense of $58 million in both 2022 and 2021. Future estimated amortization expense as of December 31, 2022 is as follows: $54 million in 2023; $49 million in 2024; $37 million in 2025; $28 million in 2026; and $23 million in 2027.

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 contributions made by the Company, 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 and the NQBP are 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 2022 and 2021.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Operating Revenues in PGE's Statement of Income, while any estimated collection from customers is recorded as a reduction in Purchased Power. For the year ended December 31, 2022, PGE's actual NVPC was $23 million above baseline NVPC, which is within the established deadband range, therefore no estimated collection from customers was recorded as of December 31, 2022. A final determination regarding the 2022 PCAM results will be made by the OPUC through a public filing and review in 2023. For the year ended December 31, 2021, actual NVPC was above baseline NVPC by $62 million, which was outside the established deadband range. Pursuant to the PCAM, as PGE's preliminary regulatory ROE was below 8.5% as determined under the related earnings test, PGE deferred $29 million, which represents 90% of the excess variance expected to be collected from customers. On October 24, 2022, PGE and Parties submitted a stipulation with the OPUC that resolved all matters related to the 2021 PCAM and would allow PGE full recovery except for $2 million, which was recorded as a charge to earnings. Amortization will occur over a two-year period beginning January 1, 2023. Order 22-440, issued November 11, 2022, adopted the stipulation approving amortization of amounts.

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 and amortization 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 Total Utility Operating Expenses 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, 2022, PGE had a net regulatory liability related to Utility Plant AROs in the amount of $7 million and a net regulatory asset related to Trojan decommissioning ARO activities of $131 million. As of December 31, 2021, PGE had a net regulatory liability related to Utility Plant AROs in the amount of $43 million and a net regulatory asset related to Trojan decommissioning ARO activities of $90 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 a liability has been 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 and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $53 million in 2022 and $48 million in 2021.

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 Revenues 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.

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,	
	2022	2021
Balance as of beginning of year	$ 26	$ 16
(Decrease)/Increase in provision *	(2)	35
Amounts written off, less recoveries	(12)	(25)
Balance as of end of year	$ 12	$ 26

* Pursuant to the Company's COVID-19 deferral, certain decreases and increases in the Provision for Uncollectible Accounts have been deferred as a net Regulatory Asset. Of the amounts recorded as decreases and increases in the Provision for Uncollectible Accounts, reductions of $10 million and increases of $29 million for the years ended December 31, 2022 and December 31, 2021, respectively, have been offset within the COVID-19 Regulatory Asset. See Note 6, Regulatory Assets and Liabilities for more information.

Net Utility Plant

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

	As of December 31,	
	2022	2021
Utility Plant		
Generation	$ 4,660	$ 4,645
Transmission	1,116	1,009
Distribution	4,813	4,470
General	950	918
Intangible	830	805
Total in service	12,369	11,847
Less: Accumulated Provision for Depreciation, Amortization, and Depletion	(5,495)	(5,168)
Total in service, net	6,874	6,679
Held for future use	35	9
Construction Work In Progress	479	317
Net Utility Plant	$ 7,388	$ 7,005

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 for each reporting period. The Company then classifies these financial assets and liabilities based on a fair value hierarchy 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, 2022 and 2021, 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):

	December 31, 2022				
	Level 1	Level 2	Level 3	Other[2]	Total
Assets:					
Temporary cash Investments	$ 150	$	$	$	$ 150
Nuclear decommissioning trust: [1]					
Debt securities:					
Domestic government	9	10			19
Corporate credit		9			9
Money market funds measured at NAV [2]				11	11
Non-qualified benefit plan trust: [3]					
Money market funds	1				1
Equity securitiesdomestic	3				3
Debt securitiesdomestic government	3				3
Price risk management activities: [1] [4]					
Electricity		93	63		156
Natural gas		225	6		231
	$ 166	$ 337	$ 69	$ 11	$ 583
Liabilities:					
Price risk management activities: [1] [4]					
Electricity	$	$ 53	$ 93	$	$ 146
Natural gas		39	8		47
	$	$ 92	$ 101	$	$ 193

(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 $31 million, which are recorded at cash surrender value.
(4)For further information regarding price risk management derivatives, see Note 5, Risk Management.

	December 31, 2021				
	Level 1	Level 2	Level 3	Other[2]	Total
Assets:					
Temporary cash investments	$ 44	$	$	$	$ 44
Nuclear decommissioning trust: [1]					
Debt securities:					
Domestic government	9	10			19
Corporate credit		14			14
Money market funds measured at NAV [2]				14	14
Non-qualified benefit plan trust: [3]					
Money market funds	1				1
Equity securitiesdomestic	4				4
Debt securitiesdomestic government	4				4
Price risk management activities: [1] [4]					
Electricity		16	1		17

Natural gas		115	5		120
	$ 62	$ 155	$ 6	$ 14	$ 237
Liabilities:					
Price risk management activities: (1) (4)					
Electricity	$	$ 33	$ 90	$	$ 123
Natural gas		13	1		14
	$	$ 46	$ 91	$	$ 137

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(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 $36 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	Weighted Average
	(in millions)						
As of December 31, 2022:							
Electricity physical forwards	$ 52	$ 93	Discounted cash flow	Electricity forward price (per MWh)	$ 35.00	$ 270.00	$ 101.27
Natural gas financial swaps	6	8	Discounted cash flow	Natural gas forward price (per Dth)	2.71	24.71	4.42
Electricity financial futures	11		Discounted cash flow	Electricity forward price (per MWh)	54.17	143.70	104.21
	$ 69	$ 101					
As of December 31, 2021:							
Electricity physical forwards	$	$ 90	Discounted cash flow	Electricity forward price (per MWh)	$ 16.66	$ 129.75	$ 43.73
Natural gas financial swaps	5	1	Discounted cash flow	Natural gas forward price (per Dth)	2.02	8.02	2.81
Electricity financial futures	1		Discounted cash flow	Electricity forward price (per MWh)	26.76	68.43	52.46
	$ 6	$ 91					

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, 2022	2021
Net liabilities from price risk management activities as of beginning of year	$ 85	$ 137
Net realized and unrealized losses/(gains) *	(84)	(50)
Net transfers from Level 3 to Level 2	31	(2)
Net liabilities from price risk management activities as of end of year	$ 32	$ 85
Level 3 net unrealized losses/(gains) that have been fully offset by the effect of regulatory accounting	$ (82)	$ (55)

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* Includes $2 million in net realized gains in 2022 and $5 million in 2021.

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, 2022 and 2021, 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 First Mortgage Bonds (FMBs) and Pollution Control Revenue Bonds (PCRBs) is classified as a Level 2 fair value measurement.

As of December 31, 2022, the carrying amount of PGE's long-term debt was $3,659 million and its estimated aggregate fair value was $2,984 million. As of December 31, 2021, the carrying amount of PGE's long-term debt was $3,299 million with an estimated aggregate fair value of $3,831 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. The Company also performs portfolio management and wholesale market sales services for third parties in the region. 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. PGE also enters into non-exchange-traded weather contract options, which are accounted for using the intrinsic value method. 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, 2022	As of December 31, 2021
Current assets:		
Commodity contracts:		
Electricity	$ 112	$ 16
Natural gas	201	86
Total current derivative assets	313	102
Noncurrent assets:		
Commodity contracts:		
Electricity	44	1
Natural gas	30	34
Total noncurrent derivative assets	74	35
Total derivative assets	$ 387	$ 137
Current liabilities:		
Commodity contracts:		
Electricity	$ 93	$ 36
Natural gas	25	11
Total current derivative liabilities	118	47
Noncurrent liabilities:		
Commodity contracts:		
Electricity	53	87
Natural gas	22	3
Total noncurrent derivative liabilities	75	90
Total derivative liabilities	$ 193	$ 137

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, 2022		As of December 31, 2021	
Commodity contracts:				
Electricity	6	MWh	4	MWh
Natural gas	211	Dth	181	Dth
Foreign currency contracts	$ 10	Canadian	$ 19	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, 2022, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $5 million, entirely for natural gas, for which PGE has posted no collateral. As of December 31, 2021, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $3 million, for which PGE has posted no collateral. Of the gross amounts recognized as of December 31, 2021, $1 million was for electricity and $2 million was for natural gas.

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, 2022	Years Ended December 31, 2021
Commodity contracts:		
Electricity	$ (187)	$ (38)
Natural Gas	(388)	(177)
Foreign currency contracts	1	

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the Statement of Income by the effects of regulatory accounting. Of the net amounts recognized in Net income, net gains of $188 million and $119 million for the years ended December 31, 2022 and 2021, 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, 2022 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2023	2024	2025	2026	2027	Thereafter	Total
Commodity contracts:							
Electricity	$ (19)	$ 10	$ 21	$ (3)	$ (3)	$ (16)	$ (10)
Natural gas	(177)	(8)	(2)	3			(184)
Net unrealized (gain)/loss	$ (196)	$ 2	$ 19	$	$ (3)	$ (16)	$ (194)

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, 2022 was $183 million, for which the Company has posted $130 million in collateral, consisting of $21 million of letters of credit and $109 million of cash. If the credit-risk-related contingent features underlying these agreements were triggered as of December 31, 2022, the cash requirement to either post as collateral or settle the instruments immediately would have been $27 million. As of December 31, 2022, PGE had no cash collateral posted 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.

As of December 31, 2022, PGE received from counterparties $156 million in collateral, consisting of $16 million of letters of credit and $140 million of cash. Increases in collateral received from counterparties is due to the increase in PGE's derivative asset position. The obligation to return cash collateral held for derivative instruments is included in Accrued expenses and other current liabilities on the Company's Comparative Balance Sheet.

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by counterparties. Credit risk may be concentrated to the extent PGE's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the 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.

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, 2022	As of December 31, 2021
Regulatory assets:			
Price risk management	(1)	$ 2	$ 55
Pension and other postretirement plans	(2)	95	131
Deferred income taxes	(6)	55	58
February 2021 ice storm and damage	(3)	78	68
Power cost adjustment mechanism	(4)	29	29
2020 Labor Day wildfire	(3)	32	46
COVID-19	(5)	22	36
Wildfire mitigation	(5)	29	
Other	Various	92	78
Total regulatory assets		$ 434	$ 501
Regulatory liabilities:			
Deferred income taxes	(7)	$ 249	$ 267
Asset retirement obligations	(6)	7	43
Price risk management	(1)	195	55
Other	Various	61	68
Total regulatory liabilities		$ 512	$ 433

(1)No amortization period 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 on derivative instruments until settlement.
(2)Recovery expected over the average service life of employees.
(3)Amortization will occur over a 7-year period starting January 1, 2023.
(4)Amortization will occur over a 2-year period starting January 1, 2023.
(5)Amortization period not yet determined.
(6)Recovery or refund expected over the estimated lives of the underlying assets and treated as a reduction to rate base.
(7)Refund expected as the balance is reversed using the average rate assumption method over the average life of the underlying assets and treated as a reduction to rate base.

On April 25, 2022, the OPUC issued Order 22-129, which adopted all stipulations agreed to by the parties to the proceeding in PGE's 2022 GRC, including the annual revenue requirement, cost of capital, capitalization ratio, and the elimination of the decoupling mechanism, although deferral related to the decoupling mechanism continued on a prorated basis through the end of 2022. In 2023 and forward, deferral related to the decoupling mechanism will cease. Key elements of the OPUC's Order also included:

- establishment of a balancing account for the Company's major storm damage recovery mechanism;
- denial of PGE's proposal for a secondary phase of the 2022 GRC regarding the Faraday capital improvement project. The Company had requested that recovery of the capital cost of improvements at the Faraday hydroelectric facility be included in the new rate base. PGE was permitted to pursue recovery in the Company's next GRC. As of December 31, 2022, the Construction Work In Progress balance of the project was $168 million, including AFUDC and was placed in-service on January 31, 2023. The Company's 2024 GRC pursues recovery of the Faraday project in its rate base request;
- approval of an intervenor request that would require PGE to defer and refund, subject to an earnings test, the revenue requirement associated with the Company's Boardman coal-fired generating plant included in customer prices following plant closure in 2020; and
- creation of an earnings test for the deferrals for the 2020 Labor Day wildfire and the February 2021 ice storm and damage that is to be applied on a year-by-year basis.

As a result of the earnings tests outlined in the OPUC's Order, the Company has released deferrals associated with the year ended 2020, resulting in a pre-tax, non-cash charge to earnings in 2022 in the amount of $17 million. The amount recorded represents the Company's estimate based on its interpretation of the OPUC's earnings test. PGE does not expect to exceed its regulated return on equity under the earnings test methodology approved by the OPUC and as a result, no release of deferrals or earnings test reserve is expected for 2021 and 2022. The OPUC has significant discretion in making the final determination of the application of the earnings test for 2020, 2021, and 2022 that could result in additional disallowances or refunds compared to the amount reserved by the Company as of December 31, 2022, which could be material.

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.

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 and adjustments to the Trojan ARO 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.

February 2021 ice storm and damage represents the costs incurred to repair damage to PGE's transmission and distribution systems and restore power to customers as a result of the historic storms that ultimately led Oregon's Governor to declare a state of emergency in February 2021. The Company filed an application for authorization to defer emergency restoration costs for the February 2021 ice storm (OPUC Docket UM 2156), which was approved on January 26, 2022 (OPUC Order No. 22-020). On October 24, 2022, PGE and parties submitted a stipulation with the OPUC reflecting an agreement that resolved all matters related to 2021 under this deferral and would allow PGE full recovery of the deferred amounts with amortization over a seven-year period. The OPUC adopted the stipulation approving amortization of amounts with amortization that began on January 1, 2023.

*Power Cost Adjustment Mechanism*For the year ended December 31, 2021, actual NVPC was $62 million above baseline NVPC, and therefore PGE deferred $29 million, which represents 90% of the excess variance expected to be collected from customers for the year ended December 31, 2021. In conjunction with the OPUC's annual review of the Company's PCAM filing, parties reached a settlement and on October 24, 2022, PGE and parties submitted a stipulation with the OPUC reflecting an agreement that resolved all matters related to this deferral and would allow PGE full recovery except for $2 million, which was recorded as a charge to earnings. Amortization will occur over a two-year period beginning January 1, 2023. Order 22-440, issued November 8, 2022, adopted the stipulation approving amortization of amounts.

2020 Labor Day wildfire in 2020, the State experienced the most destructive wildfire season on record, with over one million acres of land burned that ultimately led Oregon's Governor to declare a state of emergency. PGE has incurred costs to replace and rebuild PGE facilities damaged by the fires, as well as address 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 (Docket UM 2115). As of December 31, 2022 and December 31, 2021, PGE's cumulative deferred costs related to the wildfire response was $31 million and $45 million, respectively. Among the provisions of Order 22-129, the OPUC established an earnings test for the 2020 Labor Day wildfire deferral. Pursuant to the earnings test outlined in the OPUC's Order, the Company has released deferrals associated with the year ended 2020, resulting in a pre-tax charge to earnings for 2022 in the amount of $15 million. The amount recorded represents the Company's estimate based on its interpretation of the OPUC's earnings test. The charge was recorded to Distribution Maintenance Expenses in the Statement of Income. On July 27, 2022, PGE made a request for amortization with the OPUC that would allow collection in customer prices over a seven-year amortization period beginning November 1, 2022. On October 24, 2022, PGE and parties submitted a stipulation with the OPUC reflecting an agreement that resolved all matters related to 2021 under this deferral and would allow PGE full recovery of the amounts deferred as of September 30, 2022, with amortization over a seven-year period. Order 22-435, issued November 3, 2022, adopted the stipulation approving amortization of amounts with amortization that began on January 1, 2023.

COVID-19 pandemic led Oregon's Governor to declare a state of emergency on March 8, 2020. Due to the adverse impacts of COVID-19 on economic activity, PGE has experienced an increase in bad debt expense, lost revenue, and other incremental costs. On March 20, 2020, PGE filed an application with the OPUC for deferral of lost revenue and certain incremental costs, such as bad debt expense, related to COVID-19. PGE, other utilities under the OPUC's jurisdiction, intervenors, and OPUC staff held discussions regarding the scope of costs incurred by utilities which may qualify for deferral under Docket UM2114, 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 OPUC adopted a proposed OPUC Staff motion for Staff to execute stipulations incorporating the terms of the Term Sheet. PGE's deferral application was approved by the OPUC on October 20, 2020 with final stipulations for the Term Sheet approved on November 3, 2020. As of December 31, 2022 and December 31, 2021, PGE's deferred balance was $22 million and $36 million, respectively, comprised primarily of bad debt expense in excess of what is currently considered and collected in customer prices. The Company has released deferrals associated with the year ended 2020, resulting in a pre-tax charge to earnings in 2022 in the amount of $2 million. The amount recorded represents the Company's estimate based on its understanding of the OPUC's intent to apply an earnings test to certain elements of utility COVID deferrals. PGE filed a request for amortization of deferred amounts on December 16, 2022, which reflected a $12 million adjustment primarily related to bad debt write-offs being lower than estimated. The request for amortization has an effective date of April 1, 2023, and is still pending the approval of the OPUC. Amortization of any deferred costs will remain subject to OPUC review prior to amortization in customer prices and would be subject to an earnings test. PGE believes amounts deferred are 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. The OPUC's conclusion of overall prudence and the application of an earnings review could result in a portion, or all, of PGE's deferrals being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

Wildfire mitigation represents incremental costs and investments made by PGE under SB 762, which was passed in the 2021 legislative session with an effective date of July 19, 2021. SB 762 instructs public utilities to develop, implement, and execute a wildfire protection plan, in which reasonable costs can be recovered through prices to all customers. The outcome of PGE's 2022 GRC provided an annual amount of $24 million to be collected in base rates in regards to wildfire mitigation efforts. On July 1, 2022, PGE filed an application for reauthorization of OPUC Docket UM 2019 to defer incremental wildfire mitigation costs that exceed the amount granted in base rates. As of December 31, 2022, PGE's deferred balance related to wildfire mitigation was $28 million. While the Company believes the full amount of the deferral is probable of recovery, the OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusions of overall prudence, or application of a potential earnings test, could result in a portion, or all, of PGE's deferral being disallowed for recovery. Such disallowance would be recognized as a charge to earnings.

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 reversing 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,

	2022	2021
Trojan decommissioning activities	$ 170	$ 139
Utility plant	86	95
Non-utility property	33	35
Total asset retirement obligations	$ 289	$ 269

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. In 2022, the Company recorded an increase in the ARO of $36 million due to an increase in expected annual ISFSI operation costs. The Company also recorded Accretion Expense of $6 million and a reduction of $11 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 $6 million in 2022 for costs incurred in 2021 and $5 million in 2021 for costs incurred in 2020 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 legally required. During 2022, utility AROs decreased by $9 million, with the change comprised of new liabilities incurred of $1 million, Accretion Expense of $3 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 Nonoperating Income (Acct 421) on the Statement of Income in the period in which the revisions are probable and reasonably estimable. Non-utility AROs are not subject to regulatory deferral.

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

	Years Ended December 31,	
	2022	2021
Balance as of beginning of year	$ 269	$ 291
Liabilities incurred	1	
Liabilities settled	(27)	(18)
Accretion expense	10	10
Revisions in estimated cash flows	36	(14)
Balance as of end of year	$ 289	$ 269

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 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 Provision for Depreciation, Amortization, and Depletion, which is included in Regulatory liabilities on PGE's Comparative Balance Sheet.

NOTE 8: CREDIT FACILITIES

In September 2022, PGE amended its existing revolving credit facility. As of December 31, 2022, PGE had a $650 million revolving credit facility scheduled to expire in September 2027. The Company has the ability to expand the revolving credit facility to $750 million, if needed. 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, 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 the Company'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, 2022, PGE was in compliance with this covenant with a 56.9% debt to total capital ratio. In addition, the credit facility offers the potential for adjustments to interest rate margins and fees based on PGE's achievement of certain annual sustainability-linked metrics related to its non-emitting generation capacity and the percentage of management comprised of women and employees who identify as black, indigenous, and people of color. The Company believes these potential adjustments will have an immaterial impact on PGE's results of operations.

Under the revolving credit facility, as of December 31, 2022, 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 $650 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, 2022, PGE had no commercial paper outstanding.

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

In addition, PGE has three 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 $97 million of letters of credit were outstanding as of December 31, 2022. Outstanding letters of credit are not reflected on the Company's Comparative Balance Sheet.

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt in an aggregate amount up to $900 million through February 6, 2024.

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

	Year Ended December 31,	
	2022	2021
Average daily amount of short-term debt outstanding	$ 2	$ 139
Weighted daily average interest rate *	3.4 %	0.9 %
Maximum amount outstanding during the year	$ 135	$ 230

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

NOTE 9: LONG-TERM DEBT & OTHER FINANCING ARRANGEMENTS

Long-term debt

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

	As of December 31,	
	2022	2021
First Mortgage Bonds, rates range from 1.82% to 6.88%, with a weighted average rate of 4.09% in 2022 and 4.11% in 2021, due at various dates through 2051	$ 3,280	$ 3,180
Unsecured term bank loans, variable rate of approximately 5.30% at December 31, 2022	260	
Pollution Control Revenue Bonds, rates at 2.13% and 2.38%, due 2033	119	119
Total long-term debt	$ 3,659	$ 3,299

*First Mortgage Bonds*On November 30, 2022, PGE entered into a Bond Purchase Agreement related to the sale of $200 million in FMBs. The bonds consist of:

a series, due in 2029, in the amount of $100 million that will bear interest at an annual rate of 5.47%; and

a series, due in 2033, in the amount of $100 million that will bear interest at an annual rate of 5.56%.

The 2029 and 2033 series were issued in 2022 and funded in full on November 30, 2022 and January 13, 2023, respectively.

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.

*Term Loan*On October 21, 2022, PGE obtained a 366-day term loan from lenders in the aggregate principal of $260 million under a 366-Day Bridge Credit Agreement. The term loan bears interest for the relevant interest period at the Term Secured Overnight Financing Rate (SOFR) plus Term SOFR Adjustment Rate of 10 basis points and Applicable Margin of 87.5 basis points. The interest rate is subject to adjustment pursuant to the terms of the loan. The loan is prepayable, in whole or in part, without penalty, at any time. The credit agreement expires on October 22, 2023, with any outstanding balance due and payable on such date. The term loan is classified as Other Long-Term Debt on PGE's Comparative Balance Sheet.

*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, 2022, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2023	$ 260
2024	80
2025	
2026	
2027	160
Thereafter	3,159
	$ 3,659

Pelton/Round Butte financing arrangement

Under terms of an agreement (the "Agreement") approved by the OPUC in 2000, PGE had a 66.67% ownership interest in the 455 Megawatt (MW) Pelton/Round Butte hydroelectric project on the Deschutes River (Pelton/Round Butte), with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). In the Agreement, the CTWS had an option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte in 2021. On June 30, 2021, the CTWS notified PGE of their intent to exercise this purchase option. Under the terms of the purchase option, on January 1, 2022, PGE completed the sale of the additional undivided interest in the project at a net book value of $37 million, with no gain or loss recognized on the sale. Under terms of the Agreement, the CTWS has a second option in 2036 to purchase an undivided 0.02% interest in Pelton/Round Butte. If the second option is exercised, the CTWS' ownership percentage would exceed 50%. PGE remains the operator of the project.

PGE has agreed to purchase 100% of the CTWS' share of the project's output under a Power Purchase Agreement (PPA) through 2040. The exercise of the purchase option on January 1, 2022 was evaluated as a sale-leaseback arrangement, and PGE determined that the transaction did not qualify for sale-leaseback accounting. As a result, the transaction is accounted for as a financing arrangement. PGE will continue to record the tangible utility asset within Net Utility Plant on the Comparative Balance Sheet as if it were the legal owner and will continue to recognize Depreciation Expense over the estimated useful life. A financing obligation of $25 million was recorded in Other noncurrent liabilities in 2022. Proceeds related to the financing obligation of $25 million were recorded as a financing activity while proceeds from the sale of intangible property of $11 million and from the sale of Construction Work In Progress of $1 million were recorded as an investing activity on the statements of cash flow. The monthly PPA payments are split between Interest Charges and a reduction of the principal portion of the financing obligation. 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.

As of December 31, 2022, the future minimum payments on the financing arrangement are as follows (in millions):

Years ending December 31:	
2023	$ 2
2024	2
2025	5
2026	5
2027	5
Thereafter	69
Total Payments	88
Less: Imputed Interest	(61)
Present value of minimum payments	$ 27

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 both 2022 and 2021. PGE does not expect to contribute to the pension plan in 2023.

*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.

In 2022, PGE executed a buyout of the Non-represented Retiree Medical Plan, resulting in an $11 million settlement gain, which has been recorded in Miscellaneous income (expense), net on the Statement of Income.

*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 Management Deferred Compensation Plan (MDCP). Investments in the NQBP trust, consisting of trust-owned life insurance policies and marketable securities, provide partial 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):

	2022			2021		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust assets	$ 19	$ 19	$ 38	$ 21	$ 24	$ 45
Non-qualified benefit plan liabilities	18	67	85	27	70	97

*Investment Policy and Asset Allocation*The Finance Committee of the PGE Board of Directors 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,			
	2022		2021	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	55 %	55 %	61 %	60 %
Debt securities	45	45	39	40
Total	100 %	100 %	100 %	100 %
Other Postretirement Benefit Plans:				
Equity securities	39 %	40 %	59 %	57 %
Debt securities	61	60	41	43
Total	100 %	100 %	100 %	100 %
Non-Qualified Benefits Plans:				
Equity securities	7 %	5 %	8 %	7 %
Debt securities	9	11	13	14
Insurance contracts	84	84	79	79
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, 2022:					
Defined Benefit Pension Plan assets:					
Equity securitiesDomestic	$ 16	$	$	$	$ 16
Investments measured at NAV:					
Money market funds				4	4
Collective trust funds				525	525
Private equity funds				2	2
	$ 16	$	$	$ 531	$ 547
Other Postretirement Benefit Plans assets:					
Money market funds	$ 4	$	$	$	$ 4
Equity securities:					
Domestic		2			2
International	3				3
Debt securitiesDomestic		4			4
Investments measured at NAV:					
Money market funds				5	5
Collective trust funds				3	3
	$ 7	$ 6	$	$ 8	$ 21
As of December 31, 2021:					
Defined Benefit Pension Plan assets:					
Equity securitiesDomestic	$ 25	$	$	$	$ 25
Investments measured at NAV:					
Money market funds				6	6
Collective trust funds				764	764
Private equity funds				5	5
	$ 25	$	$	$ 775	$ 800
Other Postretirement Benefit Plans assets:					
Money market funds	$ 3	$	$	$	$ 3
Equity securities:					
Domestic		4			4
International	10				10
Debt securitiesDomestic government		6			6
Investments measured at NAV:					
Money market funds				6	6
Collective trust funds				8	8
	$ 13	$ 10	$	$ 14	$ 37

* 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 represented 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, 2022 and 2021. 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	
	2022	2021	2022	2021	2022	2021
Benefit obligation:						
As of January 1	$ 972	$ 1,010	$ 71	$ 76	$ 27	$ 28
Service cost	17	19	1	2		
Interest cost	28	27	2	2	1	1
Actuarial gain	(255)	(26)	(15)	(5)	(7)	
Benefit payments	(69)	(47)	(4)	(5)	(3)	(2)
Administrative expenses	(3)	(3)				
Plan amendment	5	(8)	1	1		
Plan settlements			(13)			
As of December 31	$ 695	$ 972	$ 43	$ 71	$ 18	$ 27
Fair value of plan assets:						
As of January 1	$ 800	$ 753	$ 37	$ 35	$ 21	$ 19
Actual return on plan assets	(181)	97	(6)	4	(2)	1
Company contributions			7	3	3	3
Benefit payments	(69)	(47)	(4)	(5)	(3)	(2)
Administrative expenses	(3)	(3)				
Plan settlements			(13)			
As of December 31	$ 547	$ 800	$ 21	$ 37	$ 19	$ 21
Unfunded position as of December 31	$ (148)	$ (172)	$ (22)	$ (34)	$ 1	$ (6)
Accumulated benefit plan obligation as of December 31	$ 656	$ 885	N/A	N/A	$ 17	$ 23
Classification in Comparative Balance Sheet:						
Noncurrent asset	$	$	$	$	$ 19	$ 21
Current liability			(1)		(2)	(2)
Noncurrent liability	(148)	(172)	(21)	(34)	(16)	(25)
Net asset (liability)	$ (148)	$ (172)	$ (22)	$ (34)	$ 1	$ (6)
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ (28)	$ (78)	$ (8)	$ (7)	$ (7)	$ (1)
Net settlement gain			11			
Net prior service credit	5	(9)				
Amortization of net actuarial loss	(15)	(22)			(1)	(1)
Amortization of prior service credit	2			1		
	$ (36)	$ (109)	$ 3	$ (6)	$ (8)	$ (2)
Amounts included in AOCL: *						
Net actuarial loss (gain)	$ 96	$ 139	$ (7)	$ (3)	$ 6	$ 14
Prior service cost	(1)	(8)		(7)		
	$ 95	$ 131	$ (7)	$ (10)	$ 6	$ 14

* 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:

For the defined benefit pension plan, actuarial gains and losses due to demographic experience, including assumption changes, were gains of $255 million and $26 million, and the changes between actual and expected return on plan assets were a loss of $227 million and a gain of $52 million, for the years ended December 31, 2022 and 2021, respectively.

For the other postretirement benefits, actuarial gains and losses due to demographic experience, including assumption changes, were gains of $15 million and $5 million, and the changes between actual and expected return on plan assets were a loss of $6 million and a gain of $2 million, for each of the years ended December 31, 2022 and 2021, 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	
	2022	2021	2022	2021	2022	2021
Service cost	$ 17	$ 19	$ 1	$ 2	$	$
Interest cost on benefit obligation	28	27	2	2	1	1
Expected return on plan						

assets	(46)	(45)	(2)	(2)		
Amortization of prior service credit	(2)			(1)		
Amortization of net actuarial loss	15	22			1	1
Settlement gain			(11)			
Net periodic benefit cost	$ 12	$ 23	$ (10)	$ 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	
	2022	2021	2022	2021	2022	2021
Assumptions used to determine benefit obligations:						
Discount rate	5.42 %	2.92 %	5.47% - 5.51 %	2.75% - 3.11 %	5.42 %	2.92 %
Rate of compensation increase	4.21 %	4.26 %	4.04 %	4.13 %	5.10 %	4.10 %
Assumptions used to determine net periodic benefit cost:						
Discount rate	2.92 %	2.64 %	2.75% - 3.11 %	2.22% - 2.92 %	2.92 %	2.64 %
Rate of compensation increase	4.26 %	3.65 %	4.13 %	4.58 %	4.10 %	4.10 %
Long-term rate of return on plan assets	6.75 %	6.88 %	4.83 %	5.04 %	N/A	N/A

As of December 31, 2022, 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 0.50% reduction in the expected long-term rate of return on plan assets, or a 0.50% reduction in the discount rate, would have the effect of increasing the 2022 net periodic pension expense by approximately $4 million and $6 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					
	2023	2024	2025	2026	2027	2028 - 2032
Defined benefit pension plan	$ 59	$ 54	$ 54	$ 54	$ 53	$ 262
Other postretirement benefits	4	4	5	5	3	14
Non-qualified benefit plans	2	2	2	2	2	8
Total	$ 65	$ 60	$ 61	$ 61	$ 58	$ 284

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 $29 million in 2022, and $26 million in 2021 and 2020.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,	
	2022	2021
Current:		
Federal	$ 9	$ 4
State and local	24	14
	33	18
Deferred:		
Federal	(1)	
State and local	7	5
	6	5
Income tax expense	$ 39	$ 23

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,	
	2022	2021
Federal statutory tax rate	21.0 %	21.0 %
Federal tax credits (1)	(11.6)	(11.9)

State and local taxes, net of federal tax benefit	8.8	8.9
Flow through depreciation and cost basis differences	0.8	(0.2)
Local tax flow-through adjustment		(3.2)
Reversal of excess deferred income tax (2)	(4.5)	(4.8)
Other	(0.2)	(1.2)
Effective tax rate	14.3 %	8.6 %

(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 will end at various dates through 2030.
(2) The majority of excess deferred income taxes related to remeasurement under the Tax Cuts and Jobs Act is subject to Internal Revenue Service (IRS) normalization rules and will be reversed 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, 2022	As of December 31, 2021
Deferred Income Tax Assets:		
Employee benefits	$ 99	$ 115
Price risk management	54	38
Regulatory liabilities	76	39
Tax credits	102	98
Depreciation and amortization	307	312
Other	3	8
Total Deferred Income Tax Assets	641	610
Deferred Income Tax Liabilities:		
Depreciation and amortization	857	849
Price risk management	107	121
Regulatory assets	101	38
Other	16	16
Total Deferred Income Tax Liabilities	1,081	1,024
Accumulated Deferred Income Tax Liability, net	$ 440	$ 414

As of December 31, 2022, PGE has federal credit carryforwards of $102 million, consisting of PTCs, which will expire at various dates through 2042. PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2022 and 2021 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2022, and 2021, PGE had no material unrecognized tax benefits.

PGE and its subsidiaries file a 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 Company files in other states to maintain compliance with remote worker rules and regulations. These additional state filings are not significant to the financial statements. 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.

Local tax flow-through adjustment

The Company is subject to a local tax that is recovered through a supplemental tariff based on current tax expense, but for which the Company has also recognized deferred income tax expenses over time. Because it is probable that the local deferred taxes will be flowed through future customer prices in accordance with the supplemental tariff, PGE determined a corresponding regulatory asset should have been recorded. In 2021, PGE recognized a regulatory asset to defer previously recorded deferred income tax expenses in the amount of $9 million with a corresponding credit to Income tax expense reflected in the Statement of Income for the year ended December 31, 2021.

Inflation Reduction Act

The Inflation Reduction Act of 2022 ("IRA") was signed into law by President Biden on August 16, 2022. There is no immediate impact of the IRA to the year ended December 31, 2022. PGE will be closely monitoring guidance from the IRS regarding the enhanced energy credits available under the IRA. PGE expects to be able to generate and utilize increased energy credits in future periods, and as such, continues to hold that it is more likely than not that the deferred income tax assets will be realized.

NOTE 12: EQUITY-BASED PLANS

Equity Forward Sale Agreement

On October 25, 2022, PGE entered into an equity forward sale agreement (EFSA) in connection with a public offering of 10,100,000 shares of its common stock.

Effective October 28, 2022, pursuant to the terms of the EFSA, the forward counterparties borrowed 11,615,000 shares of PGE's common stock, including 1,515,000 shares in connection with the underwriters' exercise of their option to purchase additional shares, from third parties in the open market and sold the shares to a group of underwriters for $43.00 per share, less an underwriting discount equal to $1.23625 per share. PGE will not receive any proceeds from the sale of common stock until the EFSA is settled, and at that time PGE will record the proceeds, if any, in equity.

Under the terms of the EFSA, PGE may elect to settle the equity forward transactions by means of physical, cash, or net share settlement, in whole or in part, at any time on or prior to October 25, 2024, except in specified circumstances or events that would require physical settlement. To the extent that the transactions are physically settled, PGE would be required to issue and deliver shares of PGE common stock to the forward counterparty at the then applicable forward sale price. The forward sale price was initially determined to be $43.00 per share at the time the EFSA was entered into, and the amount of cash to be received by PGE upon physical settlement of the EFSA is subject to certain adjustments in accordance with the terms of the EFSA.

PGE concluded that the EFSA was an equity instrument and that it qualified for an exception from derivative accounting because the EFSA was indexed to its own stock. PGE anticipates settling the EFSA through physical settlement on or before October 25, 2024.

At December 31, 2022, the Company could have physically settled the EFSA by delivering 11,615,000 shares to the forward counterparty in exchange for cash of $483 million.

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, 2022, there were 177,145 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, 2022, there were 2,458,622 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, 2020	478,396	48.00
Granted	318,844	43.01
Forfeited	(9,754)	48.35
Vested	(212,676)	40.33
Nonvested units as of December 31, 2021	574,810	48.07
Granted	271,696	51.29
Forfeited	(76,913)	49.48
Vested	(190,132)	49.11
Nonvested units as of December 31, 2022	579,461	49.23

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 2,082,469 shares remain available for future issuance as of December 31, 2022.

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 $5 million for the year ended December 31, 2022 and $3 million for 2021.

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, Culture and Talent Committee of PGE's Board of Directors. The number of RSUs that may vest under the grants is based on three equally-weighted metrics: i) actual return on equity relative to allowed return on equity; ii) average EPS growth; and iii) average megawatts of forecast energy from clean or certain low-carbon emitting resources added to PGE's energy supply portfolioand relative total shareholder return (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 200% 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:

	2022	2021
Risk-free interest rate	1.7 %	0.2 %
Expected term (in years)	2.9	2.9
Volatility	26.4 % - 37.9 %	26.1 % - 37.9 %

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 118.7%, 88.6%, and 110.6% of awarded performance-based RSUs for the respective 2022, 2021, and 2020 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $6 million for the year ended December 31, 2022 and $7 million for 2021.

Stock-based compensation, included in Administrative and General Expenses in the Statement of Income, was $15 million for the year ended December 31, 2022, $14 million for 2021, and $11 million in 2020. Such amounts differ from those reported in Other Paid-in Capital for stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. 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 $4 million in 2022 and $1 million in 2021.

As of December 31, 2022, 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, 2022, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2023	2024	2025	2026	2027	Thereafter	Total
Capital and other purchase commitments	$ 239	$ 70	$ 36	$ 5	$ 2	$ 43	$ 395
Purchased Power							
Electricity purchases	457	449	428	303	309	3,653	5,599
Capacity contracts	17	17	20	5	5	69	133
Public utility districts	12	12	11	10	9	23	77
Natural gas	158	43	38	37	30	202	508
Coal and transportation	27	27	27				81
Total	$ 910	$ 618	$ 560	$ 360	$ 355	$ 3,990	$ 6,793

*Capital and other purchase commitments*Certain commitments have been made for 2023 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 2053, and power capacity contracts through 2051. Expenses associated with these commitments are recorded in Purchased Power on the Company's Statement of Income.

*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, 2022	PGE's Average Share as of December 31, 2022		Contract Expiration	Total PGE Contract Costs	
		Output	Capacity		2022	2021
			(in MW)			
Priest Rapids and Wanapum	$ 2,042	8.6 %	163	2052	$ 45	$ 26
Wells	421	18.8	113	2028	12	13

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*The Company has a coal agreement with take-or-pay provisions related to Colstrip Units 3 and 4 coal-fired generating 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, 2022, 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-service is 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, 2022 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, energy storage equipment, 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):

	2022	2021
Operating lease cost	$ 4	$ 8
Finance lease cost:		
Amortization of right-of-use assets	$ 14	$ 7
Interest on lease liabilities	15	11
Total finance lease cost	$ 29	$ 18
Variable lease cost	$ 31	$ 24

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

	Comparative Balance Sheet Classification	As of December 31, 2022	2021
Operating Leases:			
Operating lease right-of-use assets	Net Utility Plant	$ 22	$ 25
Current liabilities	Obligations Under Capital Leases - Current	$ 4	$ 4
Noncurrent liabilities	Obligations Under Capital Leases - Noncurrent	18	22
Total operating lease liabilities *		$ 22	$ 26
Finance Leases:			
Finance lease right-of-use assets	Utility Plant	$ 305	$ 291
Current liabilities	Obligations Under Capital Leases - Current	$ 20	$ 20
Noncurrent liabilities	Obligations Under Capital Leases - Noncurrent	294	273
Total finance lease liabilities *		$ 314	$ 293

* Included in lease liabilities are $186 million and $161 million related to power purchase agreements for the years ended December 31, 2022 and 2021, respectively.

Lease term and discount rates were as follows:

	December 31, 2022	December 31, 2021
Weighted Average Remaining Lease Term (in years)		
Operating leases	44	40
Finance leases	22	23
Weighted Average Discount Rate		
Operating leases	3.9 %	3.8 %
Finance leases	4.9 %	5.0 %

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, 2022, maturities of lease liabilities were as follows (in millions):

	Operating Leases	Finance Leases
2023	$ 4	$ 20
2024	3	20
2025	1	27
2026	1	27
2027	1	27
Thereafter	42	382
Total lease payments	52	503
Less imputed interest	(30)	(189)
Total	$ 22	$ 314

Supplemental cash flow information related to leases for the years indicated was as follows (in millions):

	2022	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 4	$ 8	$ 8
Operating cash flows from finance leases	15	11	10
Financing cash flows from finance leases	7	6	$ 6
Right-of-use assets obtained in leasing arrangements:			
Operating leases	$	$ (12)	$
Finance leases	29	153	

NOTE 16: JOINTLY-OWNED PLANT

As of December 31, 2022, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation (1)	Construction Work In Progress
Colstrip	20.00 %	1986	$ 571	$ 421	$
Pelton/Round Butte (2)	50.01 %	1958 / 1964	210	69	12
Total			$ 781	$ 490	$ 12

(1) Excludes AROs and accumulated asset retirement removal costs.
(2) PGE operates the Pelton/Round Butte Project and had a 66.67% ownership interest as of December 31, 2021. Effective January 1, 2022, PGE sold an additional 16.66% ownership interest to the party who holds the remaining ownership interest, resulting in PGE's 50.01% ownership interest.

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 2020. The Company has begun decommissioning the facility. As of December 31, 2022, PGE's ARO liability for its 90% share of the decommissioning costs was $13 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. 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.

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 has been included among more than one hundred Potentially Responsible Parties (PRPs) as it historically owned or operated property near the river.

A Portland Harbor site remedial investigation was 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 Portland Harbor that had 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, and PGE estimates undiscounted total remediation costs for Portland Harbor per the ROD could range from $1.9 billion to $3.5 billion. 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 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 Company anticipates that remedial design 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 announced in February 2021 that the entirety of Portland Harbor was 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, including conclusion of 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. Based on the above facts and remaining uncertainties in the voluntary allocation process, 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. However, the Company may obtain sufficient information, prior to the final determination of allocation percentages among PRPs, to develop a reasonable estimate, or range, of its potential liability that would require recording of the estimate, or low end of the range. The Company's liability related to the cost of remediating Portland Harbor 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, 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, 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. 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 costs related to EPA and NRD liabilities on 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 estimated liabilities and environmental expenditures related to Portland Harbor through a combination of third-party proceeds, including but not limited to 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 GRC. 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 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.

Governmental Investigations

In March, April, and May 2021, the Division of Enforcement of the Commodity Futures Trading Commission (the "CFTC"), the Division of Enforcement of the SEC, and the Division of Enforcement of the FERC, respectively, informed the Company they are conducting investigations arising out of the energy trading losses the Company previously announced in August 2020. The Company is cooperating with the CFTC, SEC, and FERC. Management cannot at this time predict the eventual scope or outcome of these matters.

Colstrip-Related Litigation

The Company has a 20% ownership interest in Colstrip, which is operated by one of the co-owners, Talen Montana, LLC (Talen). On May 10, 2022, Talen's parent company, Talen Energy Supply, LLC, filed for chapter 11 bankruptcy protection, although Colstrip continues to operate and generate electricity for PGE customers and others. Various business disagreements have arisen amongst the co-owners regarding interpretation of the Ownership and Operation (O&O) Agreement and other matters. An arbitration process has been initiated to address such business disagreements and has resulted in several legal proceedings. These legal proceedings, as well as other matters related to Colstrip, are summarized below.

*Arbitration*On March 12, 2021, co-owner NorthWestern Corporation (NorthWestern) initiated arbitration against all other co-owners of Colstrip to determine whether co-owners representing 55% or more of the ownership shares can vote to close one or both units of Colstrip, or, alternatively, whether unanimous consent is required. The O&O Agreement among the parties states that any dispute shall be submitted for resolution to a single arbitrator with appropriate expertise. This arbitration process was initially stayed as a result of the bankruptcy filing of Talen's parent company, but that stay was lifted in August 2022, by a voluntary stipulation, described below. The arbitration has once again been stayed through June 16, 2023, by agreement of the parties. PGE cannot predict the ultimate outcome of the arbitration process.

*Petition to compel arbitration*In April 2021, Avista Corporation, Puget Sound Energy Inc., PacifiCorp, and PGE (the Petitioners) petitioned in Spokane County Superior Court, Washington, Case No. 21201000-32, against NorthWestern and Talen to compel the arbitration initiated by NorthWestern that is described above. In May 2021, Talen removed the case to Federal Court (Eastern District of Washington Case No. 2:21-cv-00163-RMP). Following a hearing in July 2021, Talen's motion to transfer the case to the U.S. District Court for the District of Montana was granted. This matter is stayed, because of the bankruptcy filing of Talen's parent company. The voluntary stipulation described below (see *"Challenge to constitutionality of Montana Senate Bills 265 and 266 (MSB 265 and MSB 266)"*) did not lift the stay on this court action.

*Challenge to constitutionality of Montana Senate Bills 265 and 266 (MSB 265 and MSB 266)*On May 4, 2021, the Petitioners filed a claim against NorthWestern and Talen in U.S. District Court - Montana, Billings Division, Case No. 1:21-cv-00047-SPW-KLD, based on the passage of MSB 265, which attempted to void contractual arbitration provisions within the O&O Agreement if they do not provide for three arbitrators or provide for venue outside of the county where the plant is located. The passage of MSB 265 was supported by Defendants and purported to void the O&O Agreement among all parties, which provides for one arbitrator and venue in Spokane, Washington. The Petitioners allege that MSB 265 violated the contracts clause of the U.S. Constitution and the Montana Constitution, and is preempted by the Federal Arbitration Act (FAA). The Petitioners sought declaratory relief that MSB 265 was unconstitutional as applied to the O&O Agreement and the FAA preempted the enforcement of MSB 265.

Petitioners filed a First Amended Complaint on May 19, 2021, adding the Attorney General of Montana (Montana AG) as defendant and challenging the constitutionality of MSB 266, which purportedly gives the Montana AG authority to penalize and restrain any co-owner of Colstrip who takes steps to shut-down the plant without unanimous consent, and authority to penalize any co-owner who fails or refuses to pay the costs to maintain the plant. The Court held a hearing on August 6, 2021 and on October 13, 2021, the Court issued an order that granted the Petitioners' Motion for Preliminary Injunction, enjoining the Montana AG from enforcing MSB 266 against them.

On August 17, 2021, the Petitioners filed for partial summary judgment on their claim to declare MSB 265 preempted by the FAA and unconstitutional. On October 29, 2021, the Petitioners filed a motion for partial summary judgment on their claim to declare MSB 266 unconstitutional and unenforceable. A decision on this matter had been stayed as a result of the bankruptcy filing of Talen's parent company, but the stay was lifted by a voluntary stipulation filed by Petitioners, Talen, and NorthWestern, and ordered by the bankruptcy court on August 25, 2022. On September 29, 2022, the Magistrate Judge issued Findings and Recommendations, which were adopted in full by the Court on October 19, 2022, granting both of the Petitioners' motions for summary judgment regarding the constitutionality of MSB 265 and MSB 266 by finding that MSB 266 was unconstitutional, and MSB 265 was unconstitutional and in the alternative preempted by the FAA.

*Complaint to implement MSB 265*On May 4, 2021, Talen filed a complaint against the Petitioners and NorthWestern, in the Thirteenth Judicial District Court in the State of Montana, as an attempt to implement Montana laws when determining the language of the O&O agreement based on the recent enactment of MSB 265. The case was subsequently removed to the U.S. District Court - Montana, Billings Division, Case No. 1:21-cv-00058-SPW-TJC. This matter is stayed, because of the bankruptcy filing of Talen's parent company.

*Richard Burnett; Colstrip Properties Inc., et al v. Talen Montana, LLC; PGE, et al*In December 2020, the original claim was filed in the Montana Sixteenth Judicial District Court, Rosebud County, Cause No. CV-20-58. The plaintiffs allege they have suffered adverse effects from the defendants' coal dust. In August 2021, the claim was amended to add PGE as a defendant. Plaintiffs are seeking economic damages, costs and disbursements, punitive damages, attorneys' fees, and an injunction prohibiting defendants from allowing coal dust to blow onto plaintiffs' properties, as determined by the Court. The Court set trial to begin September 26, 2023. This matter was stayed as a result of the bankruptcy filing of Talen's parent company. On September 23, 2022, by stipulation by the parties and order of the Court, the stay was modified to allow for some limited discovery by the parties in this matter. Pursuant to a stipulation by the parties, litigation has resumed and the parties are working through discovery issues.

Since these lawsuits (except for the challenge to constitutionality of MSB 265 and MSB 266) are in early stages, the Company is unable to predict outcomes or estimate a range of reasonably possible losses.

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 known matters, individually and in the aggregate, will not have a material impact on its financial position, results of operations, or cash flows, these matters are subject to inherent uncertainties, and management's view of these matters may change in the future.

Name of Respondent:	This report is:	Date of Report:	Year/Period of Report
Portland General Electric Company	(1) An Original (2) A Resubmission	04/14/2023	End of: 2022/ Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	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 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				(11,104,905)	(808)	0	(11,105,713)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				[(a)] 1,176,000	0		1,176,000		
3	Preceding Quarter/Year to Date Changes in Fair Value							0		
4	Total (lines 2 and 3)				1,176,000	0	0	1,176,000	245,390,754	246,566,754
5	Balance of Account 219 at End of Preceding Quarter/Year				(9,928,905)	(808)	0	(9,929,713)		
6	Balance of Account 219 at Beginning of Current Year				(9,928,905)	(808)	0	(9,929,713)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				[(b)] 5,964,470			5,964,470		
8	Current Quarter/Year to Date Changes in Fair Value							0		
9	Total (lines 7 and 8)				5,964,470			5,964,470	238,863,845	244,828,315
10	Balance of Account 219 at End of Current Quarter/Year				(3,964,435)	(808)		(3,965,243)		

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss

Comprised of the net amount of the actuarial valuation of $1,622,070 of non-qualified benefit plans net of taxes of $(446,070).

(b) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss

Comprised of the net amount of the actuarial valuation of $8,226,855 of non-qualified benefit plans net of taxes of ($2,262,385).

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	10,325,385,620	10,325,385,620					

4	Property Under Capital Leases	350,587,756	350,587,756					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	1,693,343,600	1,693,343,600					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	12,369,316,976	12,369,316,976					
9	Leased to Others							
10	Held for Future Use	34,610,144	34,610,144					
11	Construction Work in Progress	479,229,849	479,229,849					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	12,883,156,969	12,883,156,969					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	5,495,106,410	5,495,106,410					
15	Net Utility Plant (13 less 14)	7,388,050,559	7,388,050,559					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	4,993,083,347	4,993,083,347					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	502,023,063	502,023,063					
22	Total in Service (18 thru 21)	5,495,106,410	5,495,106,410					
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	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	5,495,106,410	5,495,106,410					

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the 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) 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.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						0
3	(302) Franchise and Consents	202,223,306	1,497,815	14,824,518	0	0	188,896,603
4	(303) Miscellaneous Intangible Plant	602,686,857	38,664,357	0	0	0	641,351,214
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	804,910,163	40,162,172	14,824,518	0	0	830,247,817
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	3,328,862	0	0	0	0	3,328,862
9	(311) Structures and Improvements	116,665,202	(228,077)	136,300	0	0	116,300,825
10	(312) Boiler Plant Equipment	275,701,415	1,146,504	8,270,455	0	0	268,577,464
11	(313) Engines and Engine-Driven Generators						0
12	(314) Turbogenerator Units	76,054,309	(364,645)	6,131,402	0	0	69,558,262
13	(315) Accessory Electric Equipment	25,124,047	(52,213)	0	0	0	25,071,834
14	(316) Misc. Power Plant Equipment	6,904,354	9,077,238	138,010	0	0	15,843,582
15	(317) Asset Retirement Costs for Steam Production	34,911,263	0	0	0	0	34,911,263
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	538,689,452	9,578,807	14,676,167	0	0	533,592,092
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						0
19	(321) Structures and Improvements						0
20	(322) Reactor Plant Equipment						0
21	(323) Turbogenerator Units						0
22	(324) Accessory Electric Equipment						0
23	(325) Misc. Power Plant Equipment						0
24	(326) Asset Retirement Costs for Nuclear Production						0
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0	0	0	0	0
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	6,053,903	0	1,242,862	0	0	4,811,041
28	(331) Structures and Improvements	92,193,975	6,097,407	4,929,357	0	0	93,362,025
29	(332) Reservoirs, Dams, and Waterways	359,640,486	1,180,514	30,888,905	0	0	329,932,095
30	(333) Water Wheels, Turbines, and Generators	80,222,015	2,875,505	6,828,986	0	0	76,268,534
31	(334) Accessory Electric Equipment	37,444,129	842,203	3,646,720	0	0	34,639,612
32	(335) Misc. Power Plant Equipment	155,329,371	1,073,331	400,090	[a]15,713,716	(29,922)	171,686,406
33	(336) Roads, Railroads, and Bridges	17,661,491	1,351,895	1,772,951	0	0	17,240,435
34	(337) Asset Retirement Costs for Hydraulic Production	5,128	0	0	0	0	5,128
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	748,550,498	13,420,855	49,709,871	15,713,716	(29,922)	727,945,276

36	D. Other Production Plant						
37	(340) Land and Land Rights	21,168,735	0	0	(b)(3,018,051)	0	18,150,684
38	(341) Structures and Improvements	275,335,063	4,229,101	284,818	0	0	279,279,346
39	(342) Fuel Holders, Products, and Accessories	281,790,626	988,384	1,109	(c)(5,052,466)	0	277,725,435
40	(343) Prime Movers						0
41	(344) Generators	2,566,683,876	17,122,367	16,164,130	(d)(917,189)	0	2,566,724,924
42	(345) Accessory Electric Equipment	122,417,128	23,471,160	2,241	0	0	145,886,047
43	(346) Misc. Power Plant Equipment	58,798,769	(8,914,902)	214,636	0	0	49,669,231
44	(347) Asset Retirement Costs for Other Production	25,342,839	1,459,436	0	0	0	26,802,275
44.1	(348) Energy Storage Equipment - Production	6,337,427	(5,168)	0	(e)27,953,505	0	34,285,764
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,357,874,463	38,350,378	16,666,934	18,965,799	0	3,398,523,706
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,645,114,413	61,350,040	81,052,972	34,679,515	(29,922)	4,660,061,074
47	3. Transmission Plant						
48	(350) Land and Land Rights	18,002,014	1,291	7,574	0	0	17,995,731
48.1	(351) Energy Storage Equipment - Transmission						0
49	(352) Structures and Improvements	30,854,086	(429,556)	189,576	0	0	30,234,954
50	(353) Station Equipment	573,794,505	32,374,276	3,529,784	0	0	602,638,997
51	(354) Towers and Fixtures	51,711,990	1,298,942	23,556	0	0	52,987,376
52	(355) Poles and Fixtures	123,343,532	36,089,992	651,669	0	0	158,781,855
53	(356) Overhead Conductors and Devices	211,295,349	41,797,913	24,156	0	0	253,069,106
54	(357) Underground Conduit						0
55	(358) Underground Conductors and Devices						0
56	(359) Roads and Trails	286,332	0	0	0	0	286,332
57	(359.1) Asset Retirement Costs for Transmission Plant	34,109	0	0	0	0	34,109
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,009,321,917	111,132,858	4,426,315	0	0	1,116,028,460
59	4. Distribution Plant						
60	(360) Land and Land Rights	19,256,486	650,279	0	0	0	19,906,765
61	(361) Structures and Improvements	48,102,661	9,564,940	14,340	0	0	57,653,261
62	(362) Station Equipment	689,428,463	53,874,807	2,337,083	0	0	740,966,187
63	(363) Energy Storage Equipment – Distribution	1,550,462	27,130	0	0	0	1,577,592
64	(364) Poles, Towers, and Fixtures	506,609,632	117,064,580	5,531,645	0	0	618,142,567
65	(365) Overhead Conductors and Devices	762,610,462	54,689,294	2,522,625	0	0	814,777,131
66	(366) Underground Conduit	32,805,780	1,063,374	4,139	0	(561,371)	33,303,644
67	(367) Underground Conductors and Devices	975,884,524	27,572,315	232,808	0	0	1,003,224,031
68	(368) Line Transformers	512,200,142	26,897,178	296	0	561,371	539,658,395
69	(369) Services	554,183,785	27,890,756	2,641	0	0	582,071,900
70	(370) Meters	211,116,363	14,236,830	17,178	0	0	225,336,015
71	(371) Installations on Customer Premises	3,760,937	324,230	0	0	0	4,085,167
72	(372) Leased Property on Customer Premises						0
73	(373) Street Lighting and Signal Systems	151,985,730	20,305,849	830,827	0	0	171,460,752
74	(374) Asset Retirement Costs for Distribution Plant	476,732	0	0	0	0	476,732

75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,469,972,159	354,161,562	11,493,582	0	0	4,812,640,139
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						0
78	(381) Structures and Improvements						0
79	(382) Computer Hardware						0
80	(383) Computer Software						0
81	(384) Communication Equipment						0
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						0
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						0
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)	0	0	0	0	0	0
85	6. General Plant						
86	(389) Land and Land Rights	23,622,678	(1)	135,267	0	0	23,487,410
87	(390) Structures and Improvements	330,253,636	(6,048,965)	3,900,299	[(i)](547,703)	0	319,756,669
88	(391) Office Furniture and Equipment	131,726,215	21,647,563	24,709,457	0	0	128,664,321
89	(392) Transportation Equipment	81,740,342	17,226,397	3,113,772	0	29,922	95,882,889
90	(393) Stores Equipment	4,435,694	38,193	293,317	0	0	4,180,570
91	(394) Tools, Shop and Garage Equipment	22,898,990	2,080,713	497,596	0	0	24,482,107
92	(395) Laboratory Equipment	13,504,410	0	425,616	0	0	13,078,794
93	(396) Power Operated Equipment	46,554,288	1,295,530	2,409,342	0	0	45,440,476
94	(397) Communication Equipment	261,778,132	32,458,140	1,187,435	0	0	293,048,837
95	(398) Miscellaneous Equipment	1,283,417	971,383	2,676	0	0	2,252,124
96	SUBTOTAL (Enter Total of lines 86 thru 95)	917,797,802	69,668,953	36,674,777	(547,703)	29,922	950,274,197
97	(399) Other Tangible Property						0
98	(399.1) Asset Retirement Costs for General Plant	65,289	0	0	0	0	65,289
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	917,863,091	69,668,953	36,674,777	(547,703)	29,922	950,339,486
100	TOTAL (Accounts 101 and 106)	11,847,181,743	636,475,585	148,472,164	34,131,812	0	12,369,316,976
101	(102) Electric Plant Purchased (See Instr. 8)						0
102	(Less) (102) Electric Plant Sold (See Instr. 8)						0
103	(103) Experimental Plant Unclassified						0
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	11,847,181,743	636,475,585	148,472,164	34,131,812	0	12,369,316,976

FERC FORM No. 1 (REV. 12-05)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: MiscellaneousPowerPlantEquipmentHydraulicProductionAdjustments

Includes recognition of failed sale leaseback of 16.66% of plant ownership as well as regular activities of capitalized lease assets.

(b) Concept: LandAndLandRightsOtherProductionAdjustments

Includes activities of capitalized lease assets.

(c) Concept: FuelHoldersProductsAndAccessoriesOtherProductionAdjustments

Includes activities of capitalized lease assets.
(d) Concept: GeneratorsOtherProductionAdjustments
Includes an impact of purchase of previously leased assets as well as regular activities of capitalized lease assets.
(e) Concept: EnergyStorageEquipmentProductionOtherProductionAdjustments
Includes recognition of new leased assets as well as regular activities of capitalized lease assets.
(f) Concept: StructuresAndImprovementsGeneralPlantAdjustments
Includes activities of capitalized lease assets.

FERC FORM No. 1 (REV. 12-05)

Page 204-207

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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	(a)	(i)	543,591
3	Sewell, Washington County, OR	(b)	(j)	2,817,507
4	Sewell Easement, Washington County, OR	(c)	(k)	332,379
5	Evergreen, Washington County, OR	(d)	(l)	3,600,000
6	Boardman, Morrow County, OR	(e)	(m)	832,853
7	Woodburn, Marion County, OR	(f)	(n)	20,290,058
8	Sunset, Washington County, OR	(g)	(o)	5,872,568
9	Other Land and Land Rights	(h)	(p)	321,188
21	Other Property:			
22				
23				
24				
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47	TOTAL			34,610,144

FERC FORM No. 1 (ED. 12-96)

Page 214

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2007

(b) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2008

(c) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2009

(d) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2019

(e) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2020

(f) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2022

(g) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2022

(h) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

Various

(i) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(j) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(k) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(l) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(m) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(n) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(o) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(p) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Various

FERC FORM No. 1 (ED. 12-96)

Page 214

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Repower Faraday Units 1-5	168,332,602
2	ERP Replacement	22,953,607
3	Orenco Substation Rebuild	19,257,303
4	Oracle Utilities Upgrade	18,501,037
5	Hydro Control System Upgrade	13,928,197
6	Build Evergreen Substation	22,236,911
7	Coffee Creek Energy Storage	10,671,876
8	Helvetia Substation Addition	10,234,681
9	Horizon-Keeler BPA #2 230kV Line Build	9,064,644
10	Facilities Upgrades-EV Readiness	8,314,688
11	Digital Channel Uplift	8,167,436
12	Substation Communication Upgrade	7,794,354
13	Replace Turbine Shut-off Valves	[(a)] 7,716,735
14	Harborton Reliability Project	6,342,012
15	Reedville Substation Rebuild	5,910,841
16	ARM Replacement	5,265,320
17	Build Tonquin Substation	4,954,631
18	South Milliken Distribution Line Rebuild	4,524,716
19	Shute Substation Upgrade	4,273,056
20	Build Memorial Substation	3,898,617
21	Beaver Modernization	3,897,887
22	Blue Lake Substation Upgrade	3,742,550
23	Salem Operations Center EIFS Replacement	3,594,301
24	Bethel to Round Butte Fiber	3,236,039
25	Replace Top End Engine Parts	3,206,684
26	Zero Trust Network Security Project	3,141,669
27	River District Infrastructure - Install Vaults and Conduits	2,948,213
28	Risk Technology Optimization	2,940,488
29	Arleta-Holgate Conversion	2,861,512
30	Substation Upgrade	2,772,581
31	Stephens Substation Conversion	2,759,175
32	Centennial Substation Upgrades	2,557,452
33	IBM Integration Replacement Project	2,336,484
34	Wildfire Mitigation - OH Resiliency	2,137,404
35	Round Butte Transmission Upgrades	2,095,253
36	Integrated Operations Center - IOC	2,073,325
37	Electric Avenue Improvements	2,026,383

38	Operational Technology Visibility	1,954,122
39	Purchase Replacement Parts for 2023 Carty Outage	1,950,800
40	Substation Equipment Replacement	1,905,686
41	Carty Admin Building	1,885,497
42	CMD Network Protector Replacement	1,813,885
43	Seal Blue Heron Penetrations	1,657,203
44	Clackamas River Hydro Recreation, Aesthetic & Cultural Project	1,606,604
45	Rebuild Wind Farm Tower	1,512,480
46	Additional Cap Banks and Distribution Line	1,503,071
47	T&D Asset Relocation	1,425,588
48	Energy Storage, Microgrid Installation	1,386,353
49	Energy Storage	1,298,981
50	Facilities Management Fitness	1,224,175
51	Walker Rd, Beaverton Widening	1,191,643
52	EV Fleet Partner Pilot Project	1,120,088
53	Distribution Automation	1,115,039
54	Upgrade Faraday AWS System	1,103,930
55	GRC-IRM Compliance Software	1,097,628
56	Pelton Round Butte Mitigation Enhancement Fund	[(b)] 1,062,713
57	Hydro Structural/Reliability Upgrades	1,013,668
58	Customer Data Platform	1,011,013
59	Minor Projects, <$1 million, represents 8% of the Total CWIP Balance	38,719,018
43	Total	479,229,849

FERC FORM No. 1 (ED. 12-87)

Page 216

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: ConstructionWorkInProgress

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 50.01% share of the jointly owned costs is reported.

(b) Concept: ConstructionWorkInProgress

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 50.01% share of the jointly owned costs is reported.

FERC FORM No. 1 (ED. 12-87)

Page 216

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), 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.

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)

	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	4,722,143,167	4,722,143,167		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	335,206,965	335,206,965		
4	(403.1) Depreciation Expense for Asset Retirement Costs	3,555,122	3,555,122		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	7,059,672	7,059,672		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1					
9.2					
9.3					
9.4					
9.5					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	345,821,759	345,821,759		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(132,814,477)	(132,814,477)		
13	Cost of Removal	(10,074,148)	(10,074,148)		
14	Salvage (Credit)	3,048,345	3,048,345		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(139,840,280)	(139,840,280)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Gain/(Loss)/Adjustments/Transfers	64,958,701	[(a)] 64,958,701		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,993,083,347	4,993,083,347		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	418,965,615	418,965,615		
21	Nuclear Production				
22	Hydraulic Production-Conventional	288,594,657	288,594,657		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,168,690,097	1,168,690,097		
25	Transmission	408,972,765	408,972,765		
26	Distribution	2,402,299,018	2,402,299,018		
27	Regional Transmission and Market Operation				
28	General	305,561,195	305,561,195		
29	TOTAL (Enter Total of lines 20 thru 28)	4,993,083,347	4,993,083,347		

FERC FORM No. 1 (REV. 12-05)

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToAccumulatedDepreciation

$24,830,166 credit to accumulated reserve is due to sale of 16.66% interest in the Pelton Round Butte Hydro Plant to the Confederated Tribes of the Warm Springs (CTWS), effective 1/1/2022. The related depreciable plant was sold at Net Book Value for ~$24.1M (not including CWIP, intangible plant, or non-depreciable plant). As such the reduction in accumulated reserve was less than the reduction of gross utility plant.

$12,574 credit to accumulated reserve is due to functional class transfer of utility assets and related reserves from intangible plant to tangible utility plant.

$40,115,961 credit to accumulated reserve is due to transfer of reserve related to interim cost of removal collections for other production generation plants from the ARO balancing account regulatory liability (Account 254) to FERC accumulated depreciation (Account

108). PGE determined that only collections for terminal cost of removal is applicable to the ARO regulatory balancing account.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder 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.
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 from investments, including such revenues from 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 different 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.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	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)
1	121 SW Salmon Street Corporation							
2	Common Stock	04/01/1975		1,000			1,000	
3	Equity in Earnings			6,615,913	691,455		7,307,368	
4	Additional Paid in Capital			77,528,661			77,528,661	
5	SubTotal			84,145,574	691,455	0	84,837,029	0
6	Salmon Springs Hospitality Group							
7	Common Stock	04/09/1998		10,000			10,000	
8	Equity in Earnings			(954,682)			(954,682)	
9	SubTotal			(944,682)	0	0	(944,682)	0
42	Total Cost of Account 123.1 $		Total	83,200,892	691,455	0	83,892,347	0

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	25,459,349	29,151,034	Generation
2	Fuel Stock Expenses Undistributed (Account 152)	0	1,378	Generation
3	Residuals and Extracted Products (Account 153)	0	0	
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	21,234,237	29,239,572	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	15,421,665	17,450,425	Generation

8	Transmission Plant (Estimated)	409,865	698,537	Transmission
9	Distribution Plant (Estimated)	9,890,358	11,295,491	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[(a)]1,339,679	[(b)]1,339,679	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	48,295,804	60,023,704	
13	Merchandise (Account 155)	0	0	
14	Other Materials and Supplies (Account 156)	0	0	
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)	0	0	
16	Stores Expense Undistributed (Account 163)	2,270,648	2,754,586	
17				
18				
19				
20	TOTAL Materials and Supplies	76,025,801	91,930,702	

FERC FORM No. 1 (REV. 12-05)

Page 227

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther

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

(b) Concept: PlantMaterialsAndOperatingSuppliesOther

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

FERC FORM No. 1 (REV. 12-05)

Page 227

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	88,486		10,030		10,033		10,029		77,878		196,456	0
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)									1,321		1,321	
5	Returned by EPA												

6													
7													
8													
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	1,059										1,059	
19	Other:												
20	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	87,427		10,030		10,033		10,029		79,199		196,718	
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		193		193		193		2,270		4,050	0
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales	193								193		386	
40	Balance-End of Year	1,008		193		193		193		2,077		3,664	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)		7								2		9
45	Gains												
46	Losses												

FERC FORM No. 1 (ED. 12-95)

Page 228(ab)-229(ab)a

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8													
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
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: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Abandoned Trojan Nuclear Plant Decommissioning Costs; PGE has the authority to continue the recovery of the expense in rates until decommissioning is complete, as authorized by OPUC (Order No. 07-015, dtd 1/12/2007)	471,849,744	44,261,277		[(a)](1,900,000)	132,510,020
49	TOTAL	471,849,744	44,261,277		(1,900,000)	132,510,020

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: UnrecoveredPlantAndRegulatoryStudyCostsWrittenOff

$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 continued in Order #22-129 dtd 4/25/2022), offset in Account 407.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

	(2) A Resubmission		

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	19-081	1,178	561.7		
3	Cascade Renewable LLIR	818	561.7		
4	21-095 21-095	4,821	561.7		
5	21-096	114,819	561.7		
6	21-097	81,516	561.7		
7	21-098	56,613	561.7		
8	21-099	22,271	561.7		
9	21-100	22,000	561.7		
10	21-101	2,013	561.7		
11	22-111	100	561.7		
12	22-113	50	561.7		
13	22-115	54	561.7		
14	22-117	54	561.7		
15	LGIP System Impact Study	1,311	561.7		
16	LLIR SIS	36,000	561.7		
17	PTP-82 Dalreed TSR	23,500	561.7		
20	Total	367,118			
21	**Generation Studies**				
39	Total				
40	Grand Total	367,118			

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Tax Benefits Related to Book/Tax Basis Differences (Amort. period is based on the lives of the properties, approximately 25	42,249,813	181,872	282	2,643,125	39,788,560

	years.)					
2	Previously Flowed to Customers (Amort. period is based on the lives of the properties, approximately 25 years.)	16,025,790	68,986	283	1,002,564	15,092,212
3	Price Risk Management	55,249,497	270,527,381	182.3 / 254 / 547 / 555	323,740,934	2,035,944
4	Deferred Broker Settlement	(1)	64,185,977	134 / 254 / 547 / 555	64,185,977	(1)
5	Intervenor Funding (original deferral per OPUC Order No. 03-388 dtd 7/2/2003)	898,520	366,721		0	1,265,241
6	Coyote Springs Major Maintenance Accrual LTSA (per OPUC GRC 95-1216, dtd 11/20/1995)	3,845,858	1,380,969	553	3,263,498	1,963,329
7	Residual Deferred Account (per OPUC Order No. 10-279 dtd 7/23/2010)	62,159	59,735	254	5,513	116,381
8	Glass Insulator Deferral (per OPUC Order No. 10-478 dtd 12/17/2010; UE 215 First Revenue Requirement Stipulation) Amortization period: 56 years	5,292,562	0	571	106,333	5,186,229
9	Pension Funding Postretirement Funding (Per SFAS No. 158 adopted 12/31/2006; OPUC Order No. 07-051 dtd 2/12/2007)	131,499,571	0	219 / 228.3	36,299,132	95,200,439
10	Automated Demand Response Cost Recovery Mechanism (Per OPUC Advice No. 17-29, dtd 11/13/17), Amortizing through 12/31/2022.	1,286,483	7,282,785	182.3 / 232 / 407.3 / 421	7,615,828	953,440
11	Demand Response Testbed (Per OPUC Order No. 19-425, dtd 12/06/2019)	0	3,827,620	182.3 / 232 / 254 / 921	3,827,620	0
12	CET Deferral (2014-2018 vintages) (amortization per OPUC Order No. 17-511, dtd 12/18/17), Amortizing through 12/31/2022.	3,388,775	52,821	903	3,148,616	292,980
13	Schedule 110 Energy Efficiency (per OPUC Advice No. 10-01), Amortizing through 12/31/2022.	1	986,208	254 / 407.3 / 431 / 921	986,208	1
14	Deferred Cost - Pricing Program (Per OPUC Order No. 19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2022.	(8,113)	15,311,354	143 / 182.3 / 232 / 254 / 407.3 / 421 / 431 / 921	15,311,354	(8,113)
15	Deferred Cost - DLC Thermostat (Per OPUC Order No.19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2022.	115,138	27,631,665	182.3 / 232 / 254 / 407.3 / 431	27,746,802	1
16	Gresham Privilege Tax Collection Deferral (Advice No. 17-05, Schedule 134, dtd 02/24/17), Amortizing through 12/31/2022.	1,788,542	42,193	407.3	1,792,882	37,853
17	Portland Harbor Environmental Remediation Deferral (Per OPUC Order No. 17-071, Docket No. UM1789, dtd 03/02/17)	27,530,232	7,654,250	107 / 143 / 421 / 923	2,429,745	32,754,737
18	Non-Residential Sch 123 SNA Deferral-2020 (UM 1417, Amortization period 1/1/2022-12/31/2022)	10,399,895	2,385,864	456	12,216,999	568,760
19	Lost Revenue Recovery-2019 (UM 1417)	50,003	(32,848)	456	17,155	0
20	Interest Rate Swap (Interest Rate Hedges for Long Term Debt Amortization period: 30 years beginning April 2019)	4,271,271	0	428.1	156,264	4,115,007
21	Transportation Electrification Prgm (Per UM 1811, Order No. 18-124, dtd 4/12/2018), Amortizing through 12/31/2022.	1,083,338	1,106,142	143 / 232 / 253 / 421 / 431 / 456.1 / 908	1,792,592	396,888
22	EV Charging (Per UM 2003, Order No. 20-381, dtd 10/27/2020), Amortizing through 12/31/2022.	440,941	503,236	421 / 908	549,879	394,298
23	Income Qualified Bill Discounts (UM 2219), Amortizing through 12/31/2022.	0	5,184,775	182.3 / 254 / 431 / 903	3,879,837	1,304,938
24	Multifamily Water Heater (Per Advice Filing No. 17-06, UM-1827, Order No. 17-224, dtd 6/27/2017)	2	5,832,034	143 / 182.3 / 232 / 254 / 407.3 / 421 / 431 / 921	5,517,442	314,594
25	Community Solar (Per UM-1977, OPUC Order No. 18-477, dtd 12/19/2018), Amortizing through 12/31/2022.	1,970,117	3,369,272	232 / 407.3 / 421 / 555	2,094,429	3,244,960
26	Photovoltaic Volumetric Incentive Pilot (Per OPUC Order No. 10-198 dtd 5/28/2010) (Reauthorized OPUC Order No. 15-185 dtd 6/09/2015), Amortizing through 12/31/2022.	0	6,079,825	254 / 921	6,079,825	0
27	Residential Sch123 SNA Deferral-2019 (UM 1417)	(1,157,391)	2,937,702	254 / 421 / 456	1,780,311	0
28	Non-residential Sch 123 SNA Deferral 2019 (UM 1417)	1,268,229	168,741	421 / 456	1,436,970	0
29	Residential Battery Energy Storage Pilot (Per UM-2078, Order No. 20-208, dtd 7/6/2020), Amortizing through 12/31/2022.	284,959	272,276	232 / 421 / 908	447,153	110,082
30	Wheatridge Renewable Energy Farm (Per UE-370, Order No. 20-279, dtd 8/26/2020), Amortizing through 12/31/2022.	1,530,678	0	553	52,935	1,477,743

31	Emergency Wildfire (Per UM-2115, Order No. 20-389, dtd 10/27/2020), Amortizing period 1/1/2023-12/31/2029.	45,763,056	23,408,697	232 / 407.3 / 421 / 456 / 580 / 593 / 921	36,767,433	32,404,320
32	COVID-19 (Per UM-2064, Order No. 20-376, dtd 10/27/2020)	36,385,263	5,381,402	144 / 182.3 / 232 / 421 / 431 / 506 / 544 / 557 / 580 / 593 / 904 / 921	19,944,116	21,822,549
33	Oregon Commercial Activity Tax (Per UM-2037, UE 368, Order No. 20-029, dtd 01/29/2020)	(81,964)	8,094,468	254 / 407.3 / 407.4 / 431	8,012,505	(1)
34	OPUC Fee Deferral (Per UM-2046, Order No. 20-411, dtd 11/05/2020), Amortizing through 12/31/2022.	2,756,025	3,240,024	407.3	3,909,107	2,086,942
35	Emergency Restoration Costs (Per UM 2156, filing dtd 2/15/2021), Amortizing period 1/1/2023-12/31/2029.	68,438,274	11,001,831	232 / 421 / 593	1,487,488	77,952,617
36	Non-Residential Sch. 123 SNA Deferral-2021 (UM 1417)	6,764,780	(44,146)	456	220,556	6,500,078
37	Direct Access 2021 (Per UM-1301, Order No. 21-034, dtd 1/28/2021), Amortizing through 12/31/2022.	261,852	124,141	447	370,031	15,962
38	Microgrid Storage (UM 2113, Order No. 20-370)	897,461	592,680	407.4 / 421	137,270	1,352,871
39	Independent Evaluator (UM-2184)	16,150	481,736	232 / 431 / 557	251,046	246,840
40	PCAM 2021 (UE-395), Amortizing period 1/1/2023-12/31/2024.	28,734,542	5,697,476	555	5,155,570	29,276,448
41	Regional Power Act (RPA)	1,321,083	0	242	1,321,083	0
42	Wildfire Mitigation Plan (UM-2019)	0	81,564,386	143 / 182.3 / 232 / 421 / 456 / 571 / 580 / 583 / 588 / 593 / 908 / 920 / 921 / 930.2	53,060,519	28,503,867
43	Non-Residential Sch 123 SNA Deferral 2022 (UM 1417)	0	3,873,023	421 / 456	230,540	3,642,483
44	Direct Access 2022 (UM 1301)	0	812,149		0	812,149
45	Lease Obligation Balancing Account	0	13,334,301	254 / 547	1,367,151	11,967,150
46	Lost Revenue Recovery-2020 (UM 1417, Amortization period 1/1/2022-12/31/2022)	0	333,342	456	240,790	92,552
47	Direct Access 2020 (UM 1301)	0	24,942	254 / 421	24,942	0
48	Colstrip Decommissioning Deferral (UE-394, 5/09/2022), Amortizing through 12/31/2022.	0	177,915	456	90,929	86,986
49	KB Pipeline MMA (UE-394, 5/09/2022, amortization of 5 years)	0	133,822	182.3 / 553	95,400	38,422
50	Level III Storm (UE-394), Amortizing period 1/1/2023-12/31/2024.	0	14,100,000	229	7,050,000	7,050,000
51	Lost Revenue Recovery 2021 (UM 1417)	0	2,696,558		0	2,696,558
52	Res Sch 123 SNA 2020 (UM 1417, Amortization period 1/1/2022-12/31/2022)	0	933,435		0	933,435
44	TOTAL	500,623,391	603,329,738		669,864,398	434,088,731

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Misc. Undistributed Charges	240,726	308,222	various	362,429	186,519

2	Net Co-owner / Trust Contribution	136,672	39,664,898	various	39,324,248	477,322
3	Deferred Revolving Credit Agreement Fees (amort through Sept 2027)	2,431,227	512,000	431	511,837	2,431,390
4	Dispatchable Generation (various amort periods from 2012 and extending through 2032)	7,676,041	320,250	903	2,027,002	5,969,289
5	Utility Property Sales - Selling Expenses	367,066	41,608,885	various	41,985,027	(9,076)
47	Miscellaneous Work in Progress	86,185				681,139
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)					
49	TOTAL	10,937,917				9,736,583

FERC FORM No. 1 (ED. 12-94)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Property Related	302,579,496	298,110,021
3	Regulatory Liabilities	38,298,735	73,511,236
4	Employee Benefits	114,768,148	98,922,231
5	Price Risk Management	37,933,070	53,555,944
6	Tax Credits & NOL's	99,322,362	103,846,457
7	Other	8,664,427	[(a)]3,688,789
8	TOTAL Electric (Enter Total of lines 2 thru 7)	601,566,238	631,634,678
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	0	
17.1	Other (Specify)	9,698,967	[(b)]9,048,520
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	611,265,205	640,683,198

Notes

FERC FORM NO. 1 (ED. 12-88)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Line 7 - Other	**2021**	**2022**
Bad Debt Expense	7,266,534	3,347,172
Deferred Revenue	1,107,805	1,107,805
Nuclear Decommissioning Trust	9,227,883	9,627,992
Renewable Energy Development	977,419	(620,588)
Finance Lease Liability	(11,444,856)	(10,802,621)

Miscellaneous	1,529,644	1,029,030
Total - Line 7 - Other	8,664,427	3,688,789

(b) Concept: AccumulatedDeferredIncomeTaxes

Line 17 - Other Non-Utility	**2021**	**2022**
Property Related	9,555,916	9,071,820
Employee Benefits	143,051	(23,301)
Total - Line 17 - Other Non-Utility	9,698,967	9,048,520

FERC FORM NO. 1 (ED. 12-88)

Page 234

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

CAPITAL STOCKS (Account 201 and 204)

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

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)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	Common Stock	160,000,000			89,283,353					
6	Total	160,000,000			89,283,353	1,253,363,919				
7	Preferred Stock (Account 204)									
8	Preferred Stock	30,000,000								
11	Total	30,000,000				0				
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

FERC FORM NO. 1 (ED. 12-91)

Page 250-251

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 2023-04-14	Year/Period of Report End of: 2022/ Q4

Other Paid-in Capital

1. 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 a total of all accounts for reconciliation with the balance sheet, page 112. 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 briefly explain the origin and purpose of each donation.
b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
c. Gain or 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 that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	

2	Beginning Balance Amount	4,804,482
3	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	4,804,482
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	1,556,498
7	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	1,556,498
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	0
11	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	12,428,738
15	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
16	Ending Balance Amount	12,428,738
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	18,789,718

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	23,113,532
22	TOTAL	23,113,532

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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

1. Report by Balance Sheet Account the 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. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. 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, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, 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) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	$50mm 4.84% SERIES DUE 12/15/2048 - Order No.13-098 - 3/26/2013	221	50,000,000		311,154	0	0	12/16/2013	12/15/2048	12/16/2013	12/15/2048	50,000,000	2,420,000
3	$75mm 4.47 Series Due 12/11/2048 - Order No.16-152 - 4/21/2016	221	75,000,000		336,938	0	0	12/11/2018	12/11/2048	12/11/2018	12/11/2048	75,000,000	3,352,500
4	$150mm 2.97% Series Due 9-30-2051 - Order No.20-169 - 5/22/2020	221	150,000,000		679,471	0	0	09/30/2021	09/30/2051	09/30/2021	09/30/2051	150,000,000	4,455,000
5	5.80% SERIES DUE 6-1-2039	221	170,000,000		1,460,968	0	0	09/19/2007	06/01/2039	09/19/2007	06/01/2039	170,000,000	9,860,000
6	5.81% SERIES DUE 10-1-2037	221	130,000,000		1,109,574	0	517,518	09/19/2009	10/01/2037	09/19/2009	10/01/2037	130,000,000	7,553,000
7	$150mm 5.43% SERIES DUE 5-3-2040 - Order No.09-245 - 6/22/2009	221	150,000,000		1,034,284	0	0	11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	8,145,000
8	$150mm 4.47% SERIES DUE 6/15/2044 - Order No.13-098 - 3/26/2013	221	150,000,000		1,113,047	0	0	06/07/2013	06/15/2044	06/07/2013	06/15/2044	150,000,000	6,705,000
9	$75mm 4.47% SERIES DUE 8/14/2043 - Order No.13-098 - 3/26/2013	221	75,000,000		558,740	0	0	08/29/2013	08/14/2043	08/29/2013	08/14/2043	75,000,000	3,352,500
10	$105mm 4.74% SERIES DUE 11/15/2042 - Order No.13-098 - 3/26/2013	221	105,000,000		652,029	0	0	11/15/2013	11/15/2042	11/15/2013	11/15/2042	105,000,000	4,977,000
11	$100mm 4.39% SERIES DUE 8-15-2045 - Order No.14-145 - 4/29/2015	221	100,000,000		645,383	0	0	08/15/2014	08/15/2045	08/15/2014	08/15/2045	100,000,000	4,390,000
12	$100mm 4.44% SERIES DUE 10-15-2046 - Order No.14-145 - 4/29/2015	221	100,000,000		625,030	0	0	10/15/2014	10/15/2046	10/15/2014	10/15/2046	100,000,000	4,440,000
13	$80mm 3.51% SERIES DUE 11-15-2024 - Order No.14-145 - 4/29/2015	221	80,000,000		501,502	0	0	11/17/2014	11/15/2024	11/17/2014	11/15/2024	80,000,000	2,808,000
14	$75mm 3.55% SERIES DUE 1/15/2030 - Order No.14-399 - 11/12/2014	221	75,000,000		325,295	0	0	01/15/2015	01/15/2030	01/15/2015	01/15/2030	75,000,000	2,662,500
15	$70mm 3.50% SERIES DUE 5/15/2035 - Order No.14-399 - 11/12/2014	221	70,000,000		305,128	0	0	05/15/2015	05/15/2035	05/15/2015	05/15/2035	70,000,000	2,450,000
16	$150mm 3.98% Series Due 11/21/2047 - Order No.16-152 - 4/21/2016	221	150,000,000		(99,510)	0	0	11/21/2017	11/21/2047	11/21/2017	11/21/2047	150,000,000	5,970,000
17	$75mm 3.98% Series Due 8/3/2048 - Order No.16-152 - 4/21/2016	221	75,000,000		(44,757)	0	0	08/03/2017	08/03/2048	08/03/2017	08/03/2048	75,000,000	2,985,000
18	$200mm 4.3% Series Due 4-11- 2049 - Order No.18-453 - 12/4/2018	221	200,000,000		860,461	0	0	04/19/2019	04/11/2049	04/19/2019	04/11/2049	200,000,000	8,600,000
19	$110mm 3.34%% Series Due 10-15-2049 - Order No.18-453 - 12/4/2018	221	110,000,000		477,767	0	0	10/15/2019	10/15/2049	10/15/2019	10/15/2049	110,000,000	3,674,000

20	$160mm 3.34% Series Due 1-15-2050 - Order No.18-453 - 12/4/2018	221	160,000,000		694,934	0	0	11/15/2019	01/15/2050	11/15/2019	01/15/2050	160,000,000	5,344,000
21	$200mm 3.15% Series Due 4-1-2030 - Order No.18-453 - 12/4/2018	221	200,000,000		862,049	0	0	04/27/2020	04/01/2030	04/27/2020	04/01/2030	200,000,000	6,300,000
22	$160mm 1.84% Series Due 12-10-2027 - Order No.20-169 - 5/22/2020	221	160,000,000		645,816	0	0	12/10/2020	12/10/2027	12/10/2020	12/10/2027	160,000,000	2,944,000
23	$70mm 2.32% Series Due 12-10-2032 - Order No.20-169 - 5/22/2020	221	70,000,000		278,000	0	0	12/10/2020	12/10/2032	12/10/2020	12/01/2032	70,000,000	1,624,000
24	$100mm 1.82% Series Due 9-30-2028 - Order No.20-169 - 5/22/2020	221	100,000,000		452,981	0	0	09/30/2021	09/30/2028	09/30/2021	09/30/2028	100,000,000	1,820,000
25	$50mm 2.10% Series Due 9-30-2031 - Order No.20-169 - 5/22/2020	221	50,000,000		226,490	0	0	09/30/2021	09/30/2031	09/30/2021	09/30/2031	50,000,000	1,050,000
26	$100mm 2.20% Series Due 1-15-2034 - Order No.20-169 - 5/22/2020	221	100,000,000		452,981	0	0	09/30/2021	01/15/2034	09/30/2021	01/15/2034	100,000,000	2,206,111
27	$100mm 5.47% Series Due 11-30-2029 - Order No.22-031 - 2/10/2022	221	[a]100,000,000		[b]0	0	0	11/30/2022	11/30/2029	11/30/2022	11/30/2029	100,000,000	455,834
28	6.875% SERIES VI DUE 8-1-2033	221	50,000,000		519,257	0	437,500	08/01/2003	08/01/2033	08/01/2003	08/01/2033	50,000,000	3,437,500
29	$97.8mm CITY FORSYTH 2.125% DUE 05-01-2033 - Order No.09-099 - 3/26/2009	221	97,800,000		528,702	(1,956,000)	0	03/11/2020	05/01/2033	03/11/2020	05/01/2033	97,800,000	2,078,250
30	6.26% SERIES DUE 5-1-2031	221	100,000,000		723,856	0	0	05/26/2006	05/01/2031	05/26/2006	05/01/2031	100,000,000	6,260,000
31	$21.0mm CITY FORSYTH 2.375% DUE 05-01-2033 - Order No.09-099 - 3/26/2009	221	21,000,000		97,594	0	0	03/11/2020	05/01/2033	03/11/2020	05/01/2033	21,000,000	498,750
32	6.31% SERIES DUE 5-1-2036	221	175,000,000		1,270,565	0	0	05/16/2007	05/01/2036	05/16/2007	05/01/2036	175,000,000	11,042,500
33	Subtotal		3,398,800,000		17,605,729	(1,956,000)	955,018					3,398,800,000	133,860,445
34	Reacquired Bonds (Account 222)												
35													
36													
37													
38	Subtotal											0	
39	Advances from Associated Companies (Account 223)												
40													
41													
42													
43	Subtotal											0	
44	Other Long Term Debt (Account 224)												
45	[c] $260M 4.5% SERIES DUE TO 10-1-2023	224	260,000,000		406,149	0	0	10/21/2022	10/22/2023	10/21/2022	10/22/2023	260,000,000	2,506,202
46	Subtotal		260,000,000		406,149	0	0					260,000,000	2,506,202
33	TOTAL		3,658,800,000									3,658,800,000	136,366,647

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: BondsPrincipalAmountIssued

A $100 million, 5.56% First Mortgage Bond due in 2033 was issued in January 2023 under authorization received from the Public Utility Commission of Oregon in Order 22-031, dated 2/10/22, in Docket UF 4328.

(b) Concept: BondIssuanceExpense

$436,204 in debt issuance costs were recognized in the following year ($210,894 in 01/2023 and $225,310 in 02/2023).

(c) Concept: ClassAndSeriesOfObligationCouponRateDescription

Per Instruction Step #5: a) Principal Advanced $260,000,000 b) Interest Added to Principal $0 (paid as accrued) c) Principal Repaid During the Year $0. Determined that we did not need to file a compliance filing with the OPUC for this term loan.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	238,863,845
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion & Amortization	55,643,551
9	Deductions Recorded on Books Not Deducted for Return	
10	Price Risk Management and Mark-to-Market	(193,036,223)
11	Regulatory Credits	131,364,075
12	Other (see footnote)	[a](23,913,964)
14	Income Recorded on Books Not Included in Return	
15	Depreciation, Depletion & Amortization	20,975,198
16	Regulatory Debits	(68,121,357)
17	Other (see footnote)	[b](12,374,137)
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	89,596,530
21	State & Local Tax Deduction	22,645,152
22	Other (see footnote)	[c]7,197,032
27	Federal Tax Net Income	149,002,866
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @ 21%	31,290,602
30	PTC C/F	(17,124,649)
31	R&D Federal	(6,510,816)

32	RTA Federal Tax Adjustment	1,191,772
33	Other Items Affecting Tax	(187,688)
34	Total Federal Income Tax - PGE	8,659,221

FERC FORM NO. 1 (ED. 12-96)

Page 261

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

Line 12 - Deductions Recorded on Books Not Deducted for Return	
Qualified NDT	1,444,694
Meals & Entertainment	375,000
Political Activity	1,273,149
Bad Debts	(14,151,815)
Fines and Penalties	733
Employee Benefits	(45,704,948)
Federal Tax Expense	7,755,066
Orion Contingent Royalty Payments	(3,451,004)
Tax Finance Lease	2,318,946
Unamortized loss on reacquired debt	1,588,954
State & Local Tax Expense	30,683,985
Deferred Revenue	(120,590)
Wheatridge RECs	(5,234,679)
Miscellaneous	(691,455)
Total Other	(23,913,964)

(b) Concept: IncomeRecordedOnBooksNotIncludedInReturn

Line 17 - Income Recorded on Books Not Included in Return	
Key Man Insurance Proceeds	4,228,435
OCI	8,226,854
Miscellaneous	(81,152)
Total Other	12,374,137

(c) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Line 22 - Deductions on Return Not Charged Against Book Income	
Dividend Received Deduction	(22,000)
Prepaid	(4,423,965)
Renewable Energy Initiatives	1,610
Property Tax	(2,845,115)
Miscellaneous	92,438
Total Other	(7,197,032)

FERC FORM NO. 1 (ED. 12-96)

Page 261

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

TAXES ACCRUED, PREPAID AND CHARGES 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 known, 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 (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) 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.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) 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 (l) through (o) how the taxes were distributed. Report in column (o) 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 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) 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.

Line	Kind of Tax (See	Type of Tax	State	Tax Year	BALANCE AT BEGINNING OF YEAR		Taxes Charged	Taxes Paid During	Adjustments	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued	Prepaid Taxes (Include in				Taxes Accrued	Prepaid Taxes (Included	Electric (Account	Extraordinary Items	Adjustment to Ret. Earnings	Other

No.	Instruction 5) (a)	(b)	(c)	(d)	(Account 236) (e)	Account 165) (f)	During Year (g)	Year (h)	(i)	(Account 236) (j)	in Account 165) (k)	408.1, 409.1) (l)	(Account 409.3) (m)	(Account 439) (n)	(o)
1	FERC Resale/Coord	Federal Tax	Federal	2022	281,871	0	1,114,835	1,114,835	0	281,871	0	0	0	0	1,114,835
2	Income Tax	Federal Tax	Federal	2022	0	2,194,722	8,659,581	10,500,000	[a] (360)	0	4,035,501	9,567,596	0	0	(908,015)
3	Foreign Insurance Excise Tax	Federal Tax	Federal	2022	0	0	0	0	0	0	0	6,093	0	0	(6,093)
4	FICA (Employer Share)	Federal Tax	Federal	2022	15,354,907	0	33,790,029	47,838,702	[b] (1)	1,306,233	0	14,673,051	0	0	19,116,978
5	Unemployment	Federal Tax	Federal	2022	3,549	0	139,841	160,981	0	(17,591)	0	73,719	0	0	66,122
6	Power License	Federal Tax	Federal	2022	276,317	(147,952)	2,644,021	2,499,317	0	223,187	(345,786)	0	0	0	2,644,021
7	**Subtotal Federal Tax**				15,916,644	2,046,770	46,348,307	62,113,835	[c] (361)	1,793,700	3,689,715	24,320,459	0	0	22,027,848
8	Income Tax	Income Tax	Montana	2022	0	(547,008)	318,463	300,000	0	0	(565,471)	327,763	0	0	(9,300)
9	County & City Income Tax	Income Tax	Oregon	2022	0	664,868	1,126,040	2,020,000	0	0	1,558,828	1,150,198	0	0	(24,158)
10	**Subtotal Income Tax**				0	117,860	1,444,503	2,320,000	0	0	993,357	1,477,961	0	0	(33,458)
11	Electric Energy Producers Tax	Other License And Fees Tax	Montana	2022	184,875	0	753,337	748,861	0	189,351	0	439,967	0	0	313,370
12	**Subtotal Other License And Fees Tax**				184,875	0	753,337	748,861	0	189,351	0	439,967	0	0	313,370
13	Property Taxes	Property Tax	Montana	2022	3,278,336	0	6,207,569	6,492,306	0	2,993,599	0	4,940,019	0	0	1,267,550
14	Property Taxes	Property Tax	Oregon	2022	0	36,617,967	76,137,107	79,089,273	0	0	39,570,133	73,151,107	0	0	2,986,000
15	Property Taxes	Property Tax	Washington	2022	2,269,464	0	2,427,170	2,217,428	0	2,479,206	0	2,427,170	0	0	0
16	**Subtotal Property Tax**				5,547,800	36,617,967	84,771,846	87,799,007	0	5,472,805	39,570,133	80,518,296	0	0	4,253,550
17	Corp Excise Tax and CAT	Excise Tax	Oregon	2022	243,008	1,424,673	21,530,503	23,600,000	[d] 113,256	243,008	3,380,914	21,880,521	0	0	(350,018)
18	**Subtotal Excise Tax**				243,008	1,424,673	21,530,503	23,600,000	113,256	243,008	3,380,914	21,880,521	0	0	(350,018)
19	City Taxes & Licenses	Franchise Tax	Oregon	2022	3,623,777	0	52,122,995	51,852,985	[e] 1	3,893,788	0	52,559,650	0	0	(436,655)
20	Corporate Franchise Tax	Franchise Tax	California	2022	0	(1,385,784)	596,738	200,000	0	0	(1,782,522)	602,385	0	0	(5,647)
21	**Subtotal Franchise Tax**				3,623,777	(1,385,784)	52,719,733	52,052,985	1	3,893,788	(1,782,522)	53,162,035	0	0	(442,302)
22	Unemployment	Payroll Tax	Oregon	2022	(186,915)	0	5,497,655	4,794,050	0	516,690	0	1,810,237	0	0	3,687,418
23	Transportation Tax	Payroll Tax	Oregon	2022	502,681	0	2,349,714	2,849,042	0	3,353	0	1,230,571	0	0	1,119,143
24	Workers Comp Assessment	Payroll Tax	Oregon	2022	0	0	361,117	361,099	0	18	0	173,991	0	0	187,126
25	**Subtotal Payroll Tax**				315,766	0	8,208,486	8,004,191	0	520,061	0	3,214,799	0	0	4,993,687
26	Other State Income Tax	State Tax	Various	2022	0	0	2,300	1,275	0	0	(1,025)	0	0	0	2,300
27	**Subtotal State Tax**				0	0	2,300	1,275	0	0	(1,025)	0	0	0	2,300
28	Public Utility Comm Fees	Other Taxes and Fees	Oregon	2022	0	0	10,385,164	10,385,164	0	0	0	0	0	0	10,385,164
29	Department of Energy	Other Taxes and Fees	Oregon	2022	0	1,260,529	2,535,464	2,500,212	0	0	1,225,277	2,535,464	0	0	0
30	Department of Enviro Quality	Other Taxes and Fees	Oregon	2022	102,038	0	209,671	165,922	0	145,787	0	0	0	0	209,671
31	Water Power Fee	Other Taxes and Fees	Oregon	2022	0	734,096	602,289	0	0	0	131,807	0	0	0	602,289
32	Goods & Services Tax	Other Taxes and Fees	Canada	2022	0	0	0	162	0	(162)	0	0	0	0	0

33	**Subtotal Other Taxes and Fees**				102,038	1,994,625	13,732,588	13,051,460	0	145,625	1,357,084	2,535,464	0	0	11,197,124
40	TOTAL				25,933,908	40,816,111	229,511,603	249,691,614	112,896	12,258,338	47,207,656	187,549,502		0	41,962,101

FERC FORM NO. 1 (ED. 12-96)

Page 262-263

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: TaxAdjustments

True up adjustment

(b) Concept: TaxAdjustments

rounding adjustment, immaterial

(c) Concept: TaxAdjustments

Immaterial adjustment in state/Fed allocation. Reversed in state adjustment for net 0 change.

(d) Concept: TaxAdjustments

Other Federal Utility tax accrual adjustment & true up adjustment

(e) Concept: TaxAdjustments

rounding adjustment, immaterial

FERC FORM NO. 1 (ED. 12-96)

Page 262-263

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

OTHER DEFERRED 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	Deferred Liability for Transferred Non-Qualified Plan Benefits	516,520	421	18,586		497,934
3	Reserve for Environmental Remediation Costs	4,000,000				4,000,000
4	Clean Fuels Program OPUC 17-250 and 17-512	14,904,592	232,926	7,983,160	14,102,990	21,024,422
5	Wireless Mods & Make Ready Clearing	0	186		1,817,020	1,817,020
6	Equity Forward Transaction Credit	0	214,921	896	770,033	769,137
47	TOTAL	19,581,112		8,002,642	16,690,043	28,268,513

FERC FORM NO. 1 (ED. 12-94)

Page 269

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED DEFERRED 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.
3. Use footnotes as required.

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)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	834,236,978	50,125,801	40,227,951			182.3	10,735,892	254	8,274,639	841,673,575
3	Gas	0									0
4	Other (Specify)	0									0
5	Total (Total of lines 2 thru 4)	834,236,978	50,125,801	40,227,951				10,735,892		8,274,639	841,673,575
6											
7											
8		0									0
9	TOTAL Account 282 (Total of Lines 5 thru 8)	834,236,978	50,125,801	40,227,951				10,735,892		8,274,639	841,673,575
10	Classification of TOTAL										
11	Federal Income Tax	668,688,347	32,336,597	28,587,006				7,526,460		5,835,530	670,747,008
12	State Income Tax	164,506,273	17,789,204	11,640,945				2,765,752		1,882,547	169,771,327
13	Local Income Tax	1,042,358						443,680		556,562	1,155,240

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

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

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)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Property Related	15,699,289					254	3,969,672	182.3	2,878,590	14,608,207
4	Price Risk Management	37,989,325	89,220,098	21,905,465			254	627,540	254	2,397,382	107,073,800
5	[(a)] Regulatory Assets	114,709,831	75,370,725	96,686,350			254	2,616,764	254	2,059,837	92,837,279
6	Regulatory Liabilities										
7	[(b)] Other	15,413,458	767,772	432,659			254	21,594	254	254,908	15,981,885
9	TOTAL Electric (Total of lines 3 thru 8)	183,811,903	165,358,595	119,024,474				7,235,570		7,590,717	230,501,171
10	Gas										
11											
12											
13											

14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	[(c)](#)7,175,995			4,371,891	2,942,792	254	80,242	182.3	118,267	8,643,119
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	190,987,898	165,358,595	119,024,474	4,371,891	2,942,792		7,315,812		7,708,984	239,144,290
20	Classification of TOTAL										
21	Federal Income Tax	132,627,526	118,093,183	85,003,014	3,122,572	2,102,119		2,890,307		2,125,825	165,973,666
22	State Income Tax	53,073,656	47,265,412	34,021,460	1,249,319	840,673		1,012,624		706,649	66,420,279
23	Local Income Tax	5,286,716						3,769,746		5,233,375	6,750,345

NOTES

FOOTNOTE DATA

(a) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

Regulatory Assets:	Beginning Balance	Ending Balance
ASC 715 Pension & Post Retirement	36,418,955	26,365,869
ASC 980 Mark-to-Market	15,301,410	563,857
Miscellaneous	(12,306,613)	(1,245,026)
Decoupling	1,775,748	2,667,144
CET Deferral	692,665	(179,348)
Feed in Tariff (FIT)	17,920,502	19,593,545
Portland Harbor (PHERA)	6,970,309	8,057,810
Covid-19	9,918,578	5,850,641
Wildfire	12,004,577	6,165,269
Storm Deferral	18,055,637	17,722,644
PCAM Deferral	7,958,063	7,274,874
Subtotal Regulatory Assets	114,709,831	92,837,279

(b) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

Other (Utility):		
Prepaid Property Tax	9,699,503	10,483,489
Unamortized Loss on Reacquired Debt	5,242,537	4,802,474
Local Flow-Through Deferred Income Tax	471,418	695,922
Subtotal Other (Utility)	15,413,458	15,981,885

(c) Concept: AccumulatedDeferredIncomeTaxesOther

Other (Non-Utility):		
Prepaid Property Tax	3,750,209	7,673,897
Unamortized Loss on Reacquired Debt	417,060	411,337
Local Flow-Through Deferred Income Tax	3,008,726	557,885
Subtotal Other (Non-Utility)	7,175,995	8,643,119

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Excess Deferred Income Taxes	266,599,827	190	19,452,101	1,598,656	248,746,382

2	Gain on Asset Sales (Per OPUC Order No. 01-777 dtd 8/31/2001), Amortizing through 12/31/2022.	1,018,137	407.4 / 421	1,478,601	977,839	517,375
3	Boardman Severance (Advice No.14-18, dtd 11/3/2014)	5,144,824	456	188,191	151,983	5,108,616
4	Asset Retirement Obligations: Balancing Account	43,399,772	108 / 407.3 / 456 / 925	46,868,699	10,491,556	7,022,629
5	Carty Major Maintenance Deferral (Per OPUC Order 15-356 UE-294 dtd 11/3/15)	1,604,110	254 / 456	5,341,072	6,398,087	2,661,125
6	Colstrip Major Maintenance Deferral (Per OPUC UE-319, Order No. 17-511, dtd 12/18/17)	4,428,028	254 / 456	755,925	1,381,540	5,053,643
7	Port Westward 1 Major Maint Deferral (Per OPUC UE 262, Order No. 13-459, dtd 12/9/2013)	3,412,752	254 / 456	4,720,803	4,857,268	3,549,217
8	Port Westward 2 Major Maintenance Deferral (Per OPUC 2015 GRC Docket UE-283, OPUC Order No.14-422, dtd 12/4/2014)	3,780,642	254 / 456	1,036,464	1,805,183	4,549,361
9	Zero Interest Program Loan Repayments (Per Advice No. 05-19 dtd 12/20/2005)	129,031	407.4	124,235	61,936	66,732
10	Schedule 110 Energy Efficiency - Balancing Account (Per Advice No. 07-25 dtd 5/20/2008), Amortizing through 12/31/2022.	965,460	182.3 / 254	1,154,627	1,636,595	1,447,428
11	Sunway 3 Investment Deferral (Per UM 1480 dtd 4/01/2010; Amortization over 20 years commencing 2010)	386,470	407.4	45,480	0	340,990
12	Trojan Decommissioning Deferral (Per OPUC UE-319, Order No.17-511, dtd 12/18/2017), Amortizing through 12/31/2022.	354,066	407	1,616,709	3,017,265	1,754,622
13	PRC Acquisition (Per OPUC UE-283 Final GRC Order No.14-422, dtd 12/04/2014, Second Partial Stipulation dtd 9/2/2014)	3,683,520	128	13,357	13,063	3,683,226
14	Deferred Broker Settlement	11,509,928	182.3	35,248,042	30,382,474	6,644,360
15	Photovoltaic Volumetric Incentive Pilot (Per OPUC Order 10-198 dtd 5/28/2010 reauthorized OPUC Order 15-185 dtd 6/09/2015), Amortizing through 12/31/2022.	7,001,359	182.3 / 407.3 / 555	6,479,582	2,482,859	3,004,636
16	Price Risk Management	55,452,621	182.3 / 547 / 555	593,276,623	733,099,296	195,275,294
17	Monet NVPC QF Deferral-2019 (Per UE-335 NVPC Stipulation, OPUC Order No. 18-405)	1		0	0	1
18	Research & Development Tax Credits (Per UM-1991, OPUC Order No. 18-464 dtd 12/14/2018), Amortizing through 12/31/2022.	2,770,095	407.4 / 411.1 / 431	4,869,320	1,687,447	(411,778)
19	Postretirement Plans (Per SFAS No. 158 adopted 12/31/2006; OPUC Order No. 07-051 dtd 2/12/2007)	9,902,180	219 / 926	14,845,045	12,031,176	7,088,311
20	Lease Obligation Balancing Account	(92,343)	182.3 / 547 / 555	4,162,141	4,254,483	(1)
21	Direct Access Deferral - 2020 (Per UM-1301, Order No. 21-034 dated 1/28/2021)	5,513	182.3	30,451	24,938	0
22	OCAT (Per UM-2037, UE 368, Order No. 20-029, dtd 01/29/2020).	770,963	182.3	770,963	974,749	974,749
23	Monet NVPC QF Deferral 2020 (Per UM-1988, Order No. 19-441 dtd 12/20/2019)	2,317,161	407.4 / 555	1,932,799	0	384,362
24	Demand Response Testbed (Per OPUC Order No. 19-425, dtd 12/06/2019)	1,548,260	182.3 / 254 / 431	10,135,973	9,524,340	936,627
25	Deferred Cost - Pricing Program (Per OPUC Order No. 19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2022.	845,196	182.3 / 254	4,788,816	5,164,807	1,221,187
26	Residential Sch123 SNA Deferral-2021 (UM 1417)	(2)	229	926,105	926,105	(2)
27	Deferred Cost - DLC Thermostat (Per OPUC Order No.19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2022.	(41,644)	182.3 / 254	1,905,547	2,427,638	480,447
28	Multifamily Water Heater (Per Advice Filing No. 17-06, UM-1827, Order No. 17-224, dtd 6/27/2017)	1,226,483	182.3 / 254	2,764,124	1,381,123	(156,518)
29	Residential Sch123 SNA Deferral-2019 (UM 1417)	801,183	182.3	801,183	0	0
30	Wheatridge RECs (UE 391), Amortizing through 12/31/2022.	4,516,317	555	5,198,181	5,320,550	4,638,686
31	Residential Sch123 SNA Deferral-2022 (UM 1417)	0	421 / 449.1	1,730,652	3,097,878	1,367,226
32	Transportation Electrification (UM 1938, UM 2003, UM 2218), Amortizing through 12/31/2022.	0	232 / 908	1,683,953	7,103,676	5,419,723

33	Metro Supportive Housing Services Tax (UM 2131), Amortizing through 12/31/2022.	0	242	955,652	955,652	0
34	Monet NVPC QF Deferral 2022 (UM 1988)	0		0	127,034	127,034
35	Income Qualified Bill Discounts (UM 2219), Amortizing though 12/31/2022.	0	182.3	878,819	878,819	0
36	Regional Power Act (RPA)	0		0	33,408	33,408
41	TOTAL	433,439,910		776,180,235	854,269,423	511,529,098

FERC FORM NO. 1 (REV 02-04)

Page 278

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

Electric Operating Revenues

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.
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 page 108, 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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	1,103,142,961	1,056,368,675	8,088,474	7,978,099	809,573	800,372
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	[a]718,662,203	[e]691,317,312	6,541,949	6,555,280	112,401	111,369
5	Large (or Ind.) (See Instr. 4)	[b]311,063,785	[f]279,876,046	4,228,987	3,713,680	269	268
6	(444) Public Street and Highway Lighting	12,274,623	11,922,891	45,651	48,995	201	200
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	2,145,143,572	2,039,484,924	18,905,061	18,296,054	922,444	912,209
11	(447) Sales for Resale	431,426,146	287,282,619	6,745,270	6,483,976	43	40
12	TOTAL Sales of Electricity	2,576,569,718	2,326,767,543	25,650,331	24,780,030	922,487	912,249
13	(Less) (449.1) Provision for Rate Refunds	(23,353,262)	17,402,956				
14	TOTAL Revenues Before Prov. for Refunds	2,599,922,980	2,309,364,587	25,650,331	24,780,030	922,487	912,249
15	Other Operating Revenues						
16	(450) Forfeited Discounts	2,462,939	1,384,370				
17	(451) Miscellaneous Service Revenues	[c]874,209	[g]629,537				
18	(453) Sales of Water and Water Power	(25,917)	(6,587)				
19	(454) Rent from Electric Property	15,711,403	15,760,270				
20	(455) Interdepartmental Rents						

21	(456) Other Electric Revenues	[d]75,460,751	[h]77,743,873					
22	(456.1) Revenues from Transmission of Electricity of Others	8,017,820	10,278,316					
23	(457.1) Regional Control Service Revenues							
24	(457.2) Miscellaneous Revenues							
25	Other Miscellaneous Operating Revenues							
26	TOTAL Other Operating Revenues	102,501,205	105,789,779					
27	TOTAL Electric Operating Revenues	2,702,424,185	2,415,154,366					

Line12, column (b) includes $ 13,262,000 of unbilled revenues.
Line12, column (d) includes 83,620 MWH relating to unbilled revenues

FERC FORM NO. 1 (REV. 12-05)

Page 300-301

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $11,824,361 in revenue related to the delivery of 547,844 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 2022, 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).

(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Includes $22,238,171 in revenue related to the delivery of 1,777,633 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2022, 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).

(c) Concept: MiscellaneousServiceRevenues

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/Test Charges

NWCPUD Scheduling

Reconnect Charges

Returned Check Charges

(d) Concept: OtherElectricRevenue

Other Electric Revenues consist of the following:	Q4-2022
Boardman Decommissioning Balancing Account	(115,203)
Boardman Inventory Write-Off	89,860
Boardman Severance	36,207
Carty Major Maintenance Deferral	(1,057,014)
Colstrip - Major Maint Accrual/Defr	(625,616)
Colstrip Decommissioning	85,787
Gain(Loss) on Gas Resale	7,455,082
General Parks & Recreation	2,363
Hydro License Implementation and Compliance	1,051,065
Lost Revenue Recovery	2,767,952
MCI Metro	3,883,684
Other	1,276,372
PW1 - Major Maint Deferral	(136,465)
PW2 - Major Maint Deferral	(768,720)
RPA Balancing	57,715,912
Sch. 32 Norm Adj	(1,078,860)
Sch. 7 Norm Adj	1,110,273
Sch. 83 Norm Adj	(5,747,801)
Steam Sales	5,059,402
Transmission Resale	4,456,470
Grand Total	75,460,751

(e) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $17,612,608 in revenue related to the delivery of 589,500 megawatt hours to customers of Energy Service Suppliers (ESSs). Oregons 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 utilitys remaining energy customers. For 2021, 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).

(f) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Includes $29,706,344 in revenue related to the delivery of 1,646,921 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2021, 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).

(g) Concept: MiscellaneousServiceRevenues

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
NWCPUD Scheduling
Reconnect Charges
Returned Check Charges

This note applies to Line 17, column (b).

(h) Concept: OtherElectricRevenue

Line 21

Other Electric Revenues consist of the following:	Q4-2021
Boardman Decommissioning Balancing Account	-183614.14
Boardman Severance	1529478.63
Carty Major Maintenance Deferral	-368712.93
Colstrip - Major Maint Accrual/Defr	818852.09
Hydro License Implementation and Compliance	950858.54
Lost Revenue Recovery	-277438.72
MCI Metro	4515841.19
Other	1146790.79
PW1 - Major Maint Deferral	-1178781.1
PW2 - Major Maint Deferral	-826853.04
RPA Balancing	65059040.1
Steam Sales	2562812.2
Transmission Resale	4712104.37
Gas Resale	9531756.11
ETO Management	23855
Sch. 7 Norm Adj	-14265080
Sch. 32 Norm Adj	2794967.92
Sch. 83 Norm Adj	499488.56
Accumulated ARO Boardman	520820.23
General Parks & Recreation	3168.45
Boardman Inventory Write-Off	174518.43
Grand Total	77743872.8

FERC FORM NO. 1 (REV. 12-05)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Number and Title of Rate Schedule	MWh Sold	Revenue	Average Number of Customers	KWh of Sales Per Customer	Revenue Per KWh Sold

No.	(a)	(b)	(c)	(d)	(e)	(f)
1	7-Residential Service	8,063,063	1,096,743,764	809,573	9,959.6491	0.136
2	15-Outdoor Area Lighting	1,672	719,197	0		0.4301
41	TOTAL Billed Residential Sales	8,064,735	1,097,462,961	809,573	9,961.7144	0.1361
42	TOTAL Unbilled Rev. (See Instr. 6)	23,739	5,680,000			0.2393
43	TOTAL	8,088,474	1,103,142,961	809,573	9,991.0373	0.1364

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 Page 310.
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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	15-Outdoor Area Lighting	11,864	2,814,119	0		0.2372
2	32-Small Nonresidential	1,552,058	206,784,232	94,550	16,415.2089	0.1332
3	38-Large Nonresidential	27,613	3,985,264	360	76,702.7778	0.1443
4	47-Small Irrigation & Drainage	16,300	3,644,748	2,750	5,927.2727	0.2236
5	49-Large Irrigation & Drainage	49,249	8,117,329	1,359	36,239.1464	0.1648
6	83-Large Nonresidential	2,909,656	301,888,186	11,731	248,031.3699	0.1038
7	85-Large Nonresidential	1,987,406	174,771,138	1,163	1,708,861.5649	0.0879
8	89-Large Nonresidential	(40,617)	(2,738,637)	1	(40,617,000)	0.0674
9	485-Large Nonresidential COS O	21,993	2,973,452	13	1,691,769.2308	0.1352
10	485-Large Nonresidential COS O	0	8,646,915	203	0	
11	515-Outdoor Area Lighting DAS	0	1,682	0		
12	532-Small Nonresidential DAS	0	222,419	129	0	
13	538-Large Nonresidential Opt.	0	2,399	2	0	
14	583-Large Nonresidential DAS	0	1,226,471	93	0	
15	585-Large Nonresidential DAS	0	1,820,486	47	0	
41	TOTAL Billed Small or Commercial	6,535,522	714,160,203	112,401	58,144.6962	0.1093
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	6,427	4,502,000			0.7005
43	TOTAL Small or Commercial	6,541,949	[(a)]718,662,203	112,401	58,201.8754	0.1099

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $11,824,361 in revenue related to the delivery of 547,844 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 2022, 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).

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	85-Large Nonresidential	559,028	45,251,061	165	3,388,048.4848	0.0809
2	89-Large Nonresidential	841,185	59,784,535	19	44,272,894.7368	0.0711
3	90-Large Nonresidential	2,737,106	175,733,630	6	456,184,333.3333	0.0642
4	485-Large Nonresidential	14,753	1,720,420	1	14,753,000	0.1166
5	489-Large Nonresidential	23,461	2,877,769	1	23,461,000	0.1227
6	689-Large Nonresidential	0	0	0		
7	485-Large Nonresidential DAS	0	5,476,772	53	0	
8	489-Large Nonresidential DAS	0	15,640,576	19	0	
9	585-Large Nonresidential DAS	0	197,969	3	0	
10	689-Large Nonresidential DAS	0	1,301,053	2	0	
41	TOTAL Billed Large (or Ind.) Sales	4,175,533	307,983,785	269	15,522,427.5093	0.0738
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	53,454	3,080,000			0.0576
43	TOTAL Large (or Ind.)	4,228,987	[(a)]311,063,785	269	15,721,141.2639	0.0736

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Includes $22,238,171 in revenue related to the delivery of 1,777,633 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2022, 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).

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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						
2						
3						
4						
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6						
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40						
41	TOTAL Billed Commercial and Industrial Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	91-Street & Hwy Lighting	14,913	5,312,414	184	81,048.913	0.3562
2	92-Traffic Signals	2,710	223,427	16	169,375	0.0824
3	95-Street & Hwy Lighting	28,028	6,738,782	1	28,028,000	0.2404
41	TOTAL Billed Public Street and Highway Lighting	45,651	12,274,623	201	227,119.403	0.2689
42	TOTAL Unbilled Rev. (See Instr. 6)	0	0			
43	TOTAL	45,651	12,274,623	201	227,119.403	0.2689

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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						
2						
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35						
36						
37						
38						
39						
40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		(23,353,262)			

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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)
41	TOTAL Billed - All Accounts	18,821,441	2,131,881,572	922,444	20,403.8847	0.1133
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	83,620	13,262,000			0.1586
43	TOTAL - All Accounts	18,905,061	2,145,143,572	922,444	20,494.5352	0.1135

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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).
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.

   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 (g) 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,line 24.
10. Footnote entries as required and provide explanations following all required data.

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)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	Avangrid Renewables (was Iberdrola)	SF	EEI				96,526	0	7,840,038	0	7,840,038
2	Atlas Energy, LLC	SF	EEI				469,436	0	31,497,883	0	31,497,883
3	Avista Corp.	SF	WSPP-1				14,191	0	1,258,502	0	1,258,502
4	BP Energy Company	SF	PGE-11				40,456	0	6,323,417	0	6,323,417
5	Black Hills Power	SF	WSPP-1				1,031	0	259,995	0	259,995
6	Bonneville Power Administration	SF	WSPP-1				275,575	0	29,561,997	0	29,561,997
7	British Columbia Hydro & Power Authoirty	SF	WSPP-1				238	0	961	0	961

8	Brookfield Energy Marketing LP	SF	WSPP-1				1,919	0	518,593	0	518,593
9	Brookfield Energy Marketing LP	OS	WSPP-1				0	0	0	[b]375,000	375,000
10	California Independent System Operator	SF	CAISO				2,359,486	0	136,356,499	0	136,356,499
11	Calpine Energy Services, L.P.	SF	EEI				22,814	0	1,645,814	0	1,645,814
12	Calpine Energy Services	OS	WSPP-1				0	0	0	[c]657,002	657,002
13	Chelan County, PUD No. 1, Washington	SF	WSPP-1				212	0	17,050	0	17,050
14	Citigroup Energy Inc.	SF	WSPP-1				26,392	0	2,959,353	0	2,959,353
15	City of Burbank	SF	WSPP-1				115	0	16,050	0	16,050
16	City of Glendale	SF	WSPP-1				48	0	5,545	0	5,545
17	City of Redding	SF	WSPP-1				13,354	0	1,246,211	0	1,246,211
18	City of Roseville	SF	WSPP-1				673	0	219,345	0	219,345
19	Clatskanie Peoples Utility District	SF	WSPP-1				2,495	0	142,549	0	142,549
20	ConocoPhillips Company	SF	WSPP-1				104,735	0	5,944,688	0	5,944,688
21	CP Energy Marketing (US) Inc	SF	WSPP-1				950	0	82,475	0	82,475
22	Douglas County, PUD No. 1, Washington	LU	WSPP-1				1,182,977	0	15,442,794	0	15,442,794
23	Dynasty Power						11,674	0	1,307,013	0	1,307,013
24	EAST BAY COMMUNITY ENERGY AUTHORITY	OS	WSPP-1				0	0	0	[d]1,549,805	1,549,805
25	EDF Trading North America, LLC	SF	WSPP-1				50,937	0	3,621,613	0	3,621,613
26	Element Markets	OS	EEI				0	0	0	[e]75,000	75,000
27	Energy Keepers, Inc.	SF	WSPP-1				2,720	0	247,052	0	247,052
28	Eugene Water & Electric Board	SF	WSPP-1				9,387	0	557,782	0	557,782
29	Exelon Generation Company, LLC	SF	EEI				4,016	0	230,255	0	230,255
30	Gridforce Energy Management	SF	NWPP				464	0	30,295	0	30,295
31	Guzman Energy LLC						8,831	0	673,773	0	673,773
32	Idaho Power Company	SF	WSPP-1				7,373	0	1,012,297	0	1,012,297
33	Load Balance Energy	OS	OATT				12,089	0	0	0	0
34	Los Angeles Dept. Water Power	SF	WSPP-1				300	0	30,000	0	30,000
35	Macquarie Energy LLC	SF	WSPP-1				263,438	0	17,283,661	0	17,283,661
36	Mercuria Energy America, LLC	SF	WSPP-1				143,550	0	18,147,091	0	18,147,091
37	Modesto Irrigation District						2,200	0	277,600	0	277,600
38	Morgan Stanley Capital Group, Inc.	SF	PGE-11				24,673	0	2,537,854	0	2,537,854
39	Morgan Stanley Capital Group, Inc.	OS	PGE-11				0	0	0	[f]1,624,996	1,624,996
40	Marin Clean Energy	OS	WSPP-1				0	0	0	[g]2,720,250	2,720,250
41	NaturEner Power Watch, LLC	SF	NWPP				32	0	1,123	0	1,123
42	Nevada Power Company						1,180	0	69,459	0	69,459
43	NextEra Energy Power Marketing, LLC	SF	WSPP-1				200	0	16,000	0	16,000
44	NorthWestern Corporation	SF	WSPP-1				164,132	0	22,700,185	0	22,700,185
45	PacifiCorp	SF	EEI				69,497	0	7,614,020	0	7,614,020
46	PacifiCorp	LU	PGE-11				16,935	0	[a]98,292	0	98,292
47	Powerex Corp.	SF	EEI				54,586	0	3,639,868	0	3,639,868
48	Orange County	OS					0	0	0	[h]1,487,500	1,487,500
49	PENINSULA CLEAN ENERGY AUTHORITY	OS	WSPP-1				0	0	0	[i]367,500	367,500

50	Public Utility District No. 2 of Grant County	SF	WSPP-1				122,403	0	7,974,529	0	7,974,529
51	Public Service Company of Colorado						10,000	0	423,536	0	423,536
52	Puget Sound Energy	SF	WSPP-1				41,991	0	3,141,663	0	3,141,663
53	Rainbow Energy Marketing Company	SF	WSPP-1				6,140	0	253,708	0	253,708
54	San Diego Community Power	OS	WSPP-1				0	0	0	[j]145,578	145,578
55	San Diego Community Energy	OS					0	0	0	[k]329,415	329,415
56	Sacramento Municipal Utility District	SF	WSPP-1				106,369	0	19,934,424	0	19,934,424
57	Sacramento Municipal Utility District	OS	WSPP-1				0	0	0	[l]600,000	600,000
58	Seattle City Light	SF	WSPP-1				12,295	0	1,548,436	0	1,548,436
59	Shell Energy North America (US), L.P.	SF	PGE-11				48,382	0	3,773,605	0	3,773,605
60	Shell Energy North America (US), L.P.	OS					0	0	0	[m]1,725,000	1,725,000
61	Snohomish County, PUD No.1, Washington	SF	WSPP-1				6,140	0	524,346	0	524,346
62	Southern California Edison	SF	EEI				40,341	0	5,791,747	0	5,791,747
63	Tacoma Power	SF	WSPP-1				4,435	0	227,540	0	227,540
64	The Energy Authority, Inc.	SF	WSPP-1				27,968	0	1,779,121	0	1,779,121
65	The Energy Authority, Inc.	OS	WSPP-1				0	0	0	[n]325,962	325,962
66	TransAlta Energy Marketing (U.S.), Inc.	SF	EEI				132,126	0	15,257,474	0	15,257,474
67	TransCanada Energy Sales Ltd.	SF	WSPP-1				44,814	0	2,669,475	0	2,669,475
68	Vitol Inc.	SF	WSPP-1				6,254	0	548,268	0	548,268
69	Umatilla Electric Cooperative	SF	EEI				673,175	0	31,786,570	0	31,786,570
70	Warm Springs Power Enterprises	OS	WSPP-1				0	0	0	[o](951,419)	(951,419)
71	Western Area Power Authority	SF	NWPP				600	0	23,200	0	23,200
72	Direct Access deferral 2022						0	0	0	[p]812,148	812,148
73	Direct Access amortization-2020						0	0	0	[q](225,865)	(225,865)
74	Portland General Electric Total	SF	OA96137	624.792270009276			0	0	0	0	0
75	ACT Commodities Inc	OS								[r]1,450,000	1,450,000
76	STX Services BV	OS								[s]1,265,640	1,265,640
15	Subtotal - RQ										0
16	Subtotal-Non-RQ						6,745,270	0	417,092,634	14,333,512	431,426,146
17	Total						6,745,270	0	417,092,634	14,333,512	431,426,146

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: EnergyChargesRevenueSalesForResale

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

(b) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to Brookwood.

(c) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to Calpine.

(d) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to East Bay.

(e) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits.
(f) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits.
(g) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits.
(h) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits.
(i) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits.
(j) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits.
(k) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits.
(l) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits.
(m) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits.
(n) Concept: OtherChargesRevenueSalesForResale
Represents sales of renewable energy credits.
(o) Concept: OtherChargesRevenueSalesForResale
Represents the sell side of a financial transaction with the counterparty.
(p) Concept: OtherChargesRevenueSalesForResale
Defer costs associated with the implementation of the annual direct access open enrollment window. See Tariff Schedule 128 filed 01/26/2007.
(q) Concept: OtherChargesRevenueSalesForResale
Amortization of deferred costs associated with the implementation of the annual direct access open enrollment window. See Tariff Schedule 128 filed 01/26/2007.
(r) Concept: OtherChargesRevenueSalesForResale
Represents sales of unbundled renewable energy credits.
(s) Concept: OtherChargesRevenueSalesForResale
Represents sales of unbundled renewable energy credits.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	67,296	(185,773)
5	(501) Fuel	44,841,981	37,330,033
6	(502) Steam Expenses	1,828,295	2,609,507

7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	3,361,485	2,845,705
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	50,099,057	42,599,472
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	651,732	815,410
16	(511) Maintenance of Structures	986,889	824,949
17	(512) Maintenance of Boiler Plant	6,560,047	7,590,866
18	(513) Maintenance of Electric Plant	920,669	1,885,553
19	(514) Maintenance of Miscellaneous Steam Plant	598,588	551,253
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	9,717,925	11,668,031
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	59,816,982	54,267,503
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-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	452,297	698,710
45	(536) Water for Power	602,289	610,988
46	(537) Hydraulic Expenses	7,072,210	7,702,703
47	(538) Electric Expenses	2,074,183	1,945,868

48	(539) Miscellaneous Hydraulic Power Generation Expenses	3,758,251	4,188,435
49	(540) Rents	1,158,024	1,224,641
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	15,117,254	16,371,345
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	453,548	631,958
54	(542) Maintenance of Structures	3,850	
55	(543) Maintenance of Reservoirs, Dams, and Waterways	830,005	404,148
56	(544) Maintenance of Electric Plant	1,844,923	1,414,401
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,248,651	1,757,699
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	5,380,977	4,208,206
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	20,498,231	20,579,551
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	3,556,159	3,393,790
63	(547) Fuel	144,392,430	199,194,004
64	(548) Generation Expenses	12,798,448	10,640,124
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	12,747,056	12,481,880
66	(550) Rents	905,333	970,116
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	174,399,426	226,679,914
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	2,949,558	2,018,896
70	(552) Maintenance of Structures	520,384	281,194
71	(553) Maintenance of Generating and Electric Plant	38,267,489	36,150,777
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,064,659	1,287,533
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	42,802,090	39,738,400
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	217,201,516	266,418,314
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	785,500,386	530,010,343
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	461,916	219,862
78	(557) Other Expenses	27,203,025	26,434,259
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	813,165,327	556,664,464
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	1,110,682,056	897,929,832
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,174,805	3,946,251
85	(561.1) Load Dispatch-Reliability	16,746	17,016
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,487,115	1,189,054

87	(561.3) Load Dispatch-Transmission Service and Scheduling	2,005,381	1,605,810
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	367,118	67,990
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	396,280	381,060
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	455,909	566,311
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	105,560,413	102,142,822
97	(566) Miscellaneous Transmission Expenses	(4,050,064)	(4,851,312)
98	(567) Rents	1,932,296	3,153,180
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	114,345,999	108,218,182
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	14,685	14,997
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	336,353	815,973
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,397,813	1,468,539
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	3,524,011	1,390,275
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	5,272,862	3,689,784
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	119,618,861	111,907,966
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 Operation Expenses (Enter Total of Lines 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	28,496,163	22,809,847
135	(581) Load Dispatching	863,050	3,293,027
136	(582) Station Expenses	2,155,925	2,135,285
137	(583) Overhead Line Expenses	3,270,062	5,903,535
138	(584) Underground Line Expenses	4,446,988	3,817,795
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	454,043	472,951
140	(586) Meter Expenses	3,251,812	2,414,677
141	(587) Customer Installations Expenses	1,747,747	1,869,800
142	(588) Miscellaneous Expenses	10,864,197	11,686,728
143	(589) Rents	876,816	2,142,897
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	56,426,803	56,546,542
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	139,431	286,705
147	(591) Maintenance of Structures	249,159	235,555
148	(592) Maintenance of Station Equipment	5,428,633	4,837,440
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	109,428,061	79,678,452
150	(594) Maintenance of Underground Lines	10,895,925	9,724,536
151	(595) Maintenance of Line Transformers	652,225	926,877
152	(596) Maintenance of Street Lighting and Signal Systems	794,138	819,978
153	(597) Maintenance of Meters	45,533	27,303
154	(598) Maintenance of Miscellaneous Distribution Plant	8,227,185	6,765,544
155	TOTAL Maintenance (Total of Lines 146 thru 154)	135,860,290	103,302,390
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	192,287,093	159,848,932
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	563,280	491,460
161	(903) Customer Records and Collection Expenses	51,954,851	58,810,443
162	(904) Uncollectible Accounts	6,985,302	5,977,000
163	(905) Miscellaneous Customer Accounts Expenses	5,747,354	5,644,153
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	65,250,787	70,923,056

165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	28,506,165	16,807,204
169	(909) Informational and Instructional Expenses	1,129,811	1,686,047
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	29,635,976	18,493,251
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	99,378,424	100,387,787
182	(921) Office Supplies and Expenses	19,835,486	17,723,785
183	(Less) (922) Administrative Expenses Transferred-Credit	15,790,312	13,283,259
184	(923) Outside Services Employed	22,639,583	23,884,579
185	(924) Property Insurance	10,366,271	9,181,298
186	(925) Injuries and Damages	6,101,935	6,121,365
187	(926) Employee Pensions and Benefits	47,092,682	62,571,896
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	11,981,778	11,828,394
190	(929) (Less) Duplicate Charges-Cr.	2,866,377	2,637,225
191	(930.1) General Advertising Expenses	790,722	1,763,214
192	(930.2) Miscellaneous General Expenses	14,549,800	15,729,906
193	(931) Rents	3,876,795	5,542,724
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	217,956,787	238,814,464
195	Maintenance		
196	(935) Maintenance of General Plant	4,595,843	3,300,424
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	222,552,630	242,114,888
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,740,027,403	1,501,217,925

FERC FORM NO. 1 (ED. 12-93)

Page 320-323

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

PURCHASED POWER (Account 555)

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.

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, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) 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 (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) 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 columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

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)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES: MegaWatt Hours Received (i)	POWER EXCHANGES: MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER: Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1	Airport Solar, LLC	LU	201				130,238	0	0	0	0	9,635,122	0	9,635,122
2	Alkali Solar	LU	201				22,956	0	0	0	0	2,177,139	0	2,177,139
3	Avangrid Renewables (was Iberdrola)	SF	PGE-11				303,783	0	0	0	0	19,933,423	0	19,933,423
4	Avangrid Renewables (was Iberdrola Renewables)	LU	PGE-11				188,842	0	0	0	0	12,791,948	0	12,791,948
5	Avangrid Renewables (was Iberdrola)	LU	PGE-11				0	0	0	0	3,127,365	0	0	3,127,365
6	Avista Corp. - AVWP (was WWP)	SF	WSPP-1				130,136	0	0	0	0	4,130,296	0	4,130,296
7	Atlas Enery	SF	EEI				109,265	0	0	0	0	11,105,953	0	11,105,953
8	BP Energy Company	SF	PGE-11				246,373	0	0	0	0	26,242,178	0	26,242,178
9	Brightwood Solar	LU	201				11,333	0	0	0	0	905,514	0	905,514
10	Ballston Solar	LU	201				3,679	0	0	0	0	350,724	0	350,724
11	Bellevue Solar	LU	Bellevue				0	0	0	0	0	154,698	0	154,698
12	Blue Marmot	OS	201				0	0	0	0	0	0	(1,187,983)	[(a)](1,187,983)
13	Bonneville Power Administration	SF	WSPP-1				1,569,555	0	0	0	0	101,539,652	0	101,539,652
14	Bonneville Power Administration	LF	WSPP-1				615,315	0	0	0	0	64,201,326	0	64,201,326
15	Bonneville Power Administration	SF	WSPP-1				0	0	0	0	9,024,000	0	0	9,024,000
16	Boring Solar	LU	201				3,839	0	0	0	0	364,001	0	364,001

17	Brookfield Energy Marketing	SF	WSPP-1				20,871	0	0	0	0	1,121,597	0	1,121,597
18	CP Energy Marketing (US)	SF	WSPP-1				22,908	0	0	0	0	2,220,742	0	2,220,742
19	California Independent System Operator	SF	CAISO				911,322	0	0	0	0	23,577,276	0	23,577,276
20	Public Utility District No. 1 of Clark County	SF	WSPP-1				24,425	0	0	0	0	1,990,638	0	1,990,638
21	Calpine Energy Services	SF	PGE-11				613,785	0	0	0	0	57,708,331	0	57,708,331
22	Case Creek Solar	LU	201				3,806	0	0	0	0	369,134	0	369,134
23	Bristol Solar LLC	LU	201				4,283	0	0	0	0	121,881	0	121,881
24	Butler Solar	LU	201				8,029	0	0	0	0	807,098	0	807,098
25	Chelan County, PUD No. 1, Washington	SF	WSPP-1				258,908	0	0	0	0	12,279,640	0	12,279,640
26	Citigroup Energy	SF	WSPP-1				54,864	0	0	0	0	3,282,693	0	3,282,693
27	Clatskanie County PUD	SF	WSPP-1				4,617	0	0	0	0	271,405	0	271,405
28	Columbia Basin Electric Cooperative Inc.	LU	OATT				739	0	0	0	0	113,158	0	113,158
29	ConocoPhillips	SF	WSPP-1				267,934	0	0	0	0	26,265,574	0	26,265,574
30	Covanta Marion	LU	QF83-118				67,263	0	0	0	0	4,682,321	0	4,682,321
31	Day Hill Solar	LU	201				3,871	0	0	0	0	307,468	0	307,468
32	Dynasty Power Inc.	SF	WSPP-1				17,193	0	0	0	0	1,607,511	0	1,607,511
33	Douglas County, PUD No. 1, Washington	[(b)] LF	WSPP-1				1,565,834	0	0	0	0	78,257,057	0	78,257,057
34	Douglas County, PUD No. 1, Washington	SF	WSPP-1				0	0	0	0	4,802,872	0	0	4,802,872
35	EDF Trading North America, LLC	SF	WSPP-1				37,084	0	0	0	0	3,005,177	0	3,005,177
36	Energy Keepers, Inc. - ENKP	SF	WSPP-1				3,653	0	0	0	0	346,407	0	346,407
37	ESI Vansycle Partners, LP	LU	WSPP-1				61,654	0	0	0	0	4,472,631	0	4,472,631
38	Eugene Water & Electric Board	LU	WSPP-1				0	0	0	0	91,000	0	0	91,000
39	Eugene Water & Electric Board	SF	ER94-717				6,968	0	0	0	0	565,368	0	565,368
40	Evergreen Biomass	LU	201				52,022	0	0	0	0	5,035,259	0	5,035,259
41	Exelon Generation Co.	SF	WSPP-1				104,479	0	0	0	0	10,754,189	0	10,754,189
42	Falls Creek Hydro	LU	201				16,664	0	0	0	0	1,476,184	0	1,476,184
43	Finley BioEnergy, LLC	LU	201				4,336	0	0	0	0	109,579	0	109,579
44	Fort Rock Solar 1	LU	201				22,477	0	0	0	0	2,094,103	0	2,094,103
45	Fort Rock Solar 4	LU	201				21,604	0	0	0	0	2,025,863	0	2,025,863
46	Gridforce Energy Management - GRID	SF	201				6	0	0	0	0	337	0	337
47	Idaho Power Company	SF	NWPP				27,898	0	0	0	0	1,401,666	0	1,401,666
48	Labish Solar	LU	WSPP-1				3,949	0	0	0	0	316,401	0	316,401
49	Macquarie Cook Power	SF	201				369,207	0	0	0	0	28,104,506	0	28,104,506
50	Mercuria Energy America, LLC	SF	WSPP-1				15,400	0	0	0	0	2,454,900	0	2,454,900
51	Milford Solar	LU	201				4,604	0	0	0	0	138,469	0	138,469
52	Middlefork Irrigation District	LU	201				18,724	0	0	0	0	485,992	0	485,992
53	Morgan Stanley Capital Group	SF	PGE-11				55,202	0	0	0	0	2,716,726	0	2,716,726
54	Montague Solar	OS	WSPP-1				0	0	0	0	0	0	[(i)](7,626,000)	(7,626,000)
	NextEra Energy Power													

55	Marketing, LLC	SF	WSPP-1				1,600	0	0	0	0	58,368	0	58,368
56	Nevada Power Company	SF	WSPP-1				25,136	0	0	0	0	1,175,947	0	1,175,947
57	NorthWestern Corporation	SF	WSPP-1				53,879	0	0	0	0	2,395,122	0	2,395,122
58	Norwest Energy 14	LU	201				3,910	0	0	0	0	389,000	0	389,000
59	Obsidian Lakeview	LU	201				27,012	0	0	0	0	2,631,308	0	2,631,308
60	OE Solar 3, LLC	LU	201				25,747	0	0	0	0	1,085,161	0	1,085,161
61	Okanogan County PUD, Washington	(c) LF	WSPP-1				193,530	0	0	0	0	9,572,472	0	9,572,472
62	O'Neil Solar	LU	201				3,892	0	0	0	0	881,419	0	881,419
63	Outback Solar	LU	Outback				9,603	0	0	0	0	997,608	0	997,608
64	Pacific Northwest Generating Company	SF	WSPP-1				44,688	0	0	0	0	3,869,214	0	3,869,214
65	PacifiCorp	SF	PGE-11				21,370	0	0	0	0	1,460,817	0	1,460,817
66	Palmer Creek Solar	LU	201				3,825	0	0	0	0	365,230	0	365,230
67	Pika Solar	LU	201				3,353	0	0	0	0	54,882	0	54,882
68	PaTu Wind	LU	WSPP-1				24,690	0	0	0	0	2,194,021	0	2,194,021
69	Duus Solar (Alchemy)	LU	201				35,399	0	0	0	0	3,371,772	0	3,371,772
70	Portland, City of	LU	#2821				85,289	0	0	0	0	3,508,782	0	3,508,782
71	Powerex	SF	PGE-11				142,406	0	0	0	0	12,810,892	0	12,810,892
72	Public Service Co of Colorado	SF	WSPP-1				300	0	0	0	0	17,500	0	17,500
73	Grant County, PUD No. 2, Washington	LU	Wanapum				879,682	0	0	0	0	19,506,606	0	19,506,606
74	Grant County, PUD No. 2, Washington	LU	Priest Rapids				879,682	0	0	0	0	19,506,606	0	19,506,606
75	Grant County, PUD No. 2, Washington	SF	WSPP-1				110,862	0	0	0	0	3,227,997	0	3,227,997
76	Greenpark Solar, LLC	LU	201				1,916	0	0	0	0	57,718	0	57,718
77	Guzman Energy LLC	SF	WSPP-1				5,075	0	0	0	0	274,871	0	274,871
78	City of Glendale	SF	WSPP-1				766	0	0	0	0	42,748	0	42,748
79	Puget Sound Energy	SF	WSPP-1				334,555	0	0	0	0	26,401,475	0	26,401,475
80	Rafael Solar	LU	201				3,846	0	0	0	0	372,586	0	372,586
81	Riley Solar	LU	201				24,406	0	0	0	0	2,273,163	0	2,273,163
82	Rainbow Energy Marketing Company	SF	WSPP-1				9,257	0	0	0	0	518,655	0	518,655
83	Rock Garden Solar	LU	201				22,183	0	0	0	0	2,082,283	0	2,082,283
84	Seattle City Light	SF	WSPP-1				100,005	0	0	0	0	5,150,159	0	5,150,159
85	Shell Energy	SF	WSPP-1				51,280	0	0	0	0	2,272,698	0	2,272,698
86	Sheep Solar	LU	201				3,724	0	0	0	0	355,256	0	355,256
87	Silverton Solar	LU	201				3,545	0	0	0	0	337,431	0	337,431
88	Sacramento Municipal Utility District	SF	WSPP-1				7,860	0	0	0	0	524,226	0	524,226
89	Snohomish County, PUD No. 1, Washington	SF	WSPP-1				91,369	0	0	0	0	2,803,047	0	2,803,047
90	SP Solar 1, LLC	LU	201				3,586	0	0	0	0	357,168	0	357,168
91	SP Solar 5, LLC	LU	201				3,773	0	0	0	0	374,946	0	374,946
92	SP Solar 6, LLC	LU	201				3,562	0	0	0	0	347,158	0	347,158

93	SP Solar 7, LLC	LU	201				3,385	0	0	0	0	310,062	0	310,062
94	SP Solar 8, LLC	LU	201				3,245	0	0	0	0	323,280	0	323,280
95	SSD Clackamas 1	LU	201				6,817	0	0	0	0	194,083	0	194,083
96	SSD Clackamas 4	LU	201				3,869	0	0	0	0	271,481	0	271,481
97	SSD Clackamas 7	LU	201				3,755	0	0	0	0	264,238	0	264,238
98	SSD Marion 1	LU	201				3,359	0	0	0	0	99,713	0	99,713
99	SSD Marion 3	LU	201				3,581	0	0	0	0	219,236	0	219,236
100	SSD Marion 5	LU	201				3,500	0	0	0	0	245,879	0	245,879
101	SSD Marion 6	LU	201				3,668	0	0	0	0	257,703	0	257,703
102	Steel Bridge	LU	201				3,050	0	0	0	0	36,545	0	36,545
103	Starvation Solar 1 LLC	LU	201				25,232	0	0	0	0	2,385,941	0	2,385,941
104	St Louis Solar	LU	201				3,951	0	0	0	0	377,720	0	377,720
105	Suluss Solar 35	LU	201				4,537	0	0	0	0	135,946	0	135,946
106	Suluss Solar 33	LU	201				4,782	0	0	0	0	143,556	0	143,556
107	Suluss Solar 22	LU	201				4,620	0	0	0	0	147,584	0	147,584
108	Suluss Solar 25	LU	201				3,359	0	0	0	0	94,462	0	94,462
109	Suluss Solar 28	LU	201				4,954	0	0	0	0	149,106	0	149,106
110	Suluss Solar 29	LU	201				3,654	0	0	0	0	110,284	0	110,284
111	Suluss Solar 17	LU	201				4,124	0	0	0	0	124,047	0	124,047
112	Suntex Solar	LU	201				23,424	0	0	0	0	2,220,197	0	2,220,197
113	Swiss Re	OS	WSPP-1				0	0	0	0	0	0	(i)(1,621,824)	(1,621,824)
114	West Hines Solar	LU	201				24,029	0	0	0	0	2,294,949	0	2,294,949
115	Tacoma, City of	SF	WSPP-1				198,359	0	0	0	0	7,661,117	0	7,661,117
116	Tenaska Power Services	SF	WSPP-1				5,933	0	0	0	0	69,937	0	69,937
117	The Energy Authority	SF	WSPP-1				90,748	0	0	0	0	5,995,115	0	5,995,115
118	Thomas Creek Solar	LU	201				3,763	0	0	0	0	301,266	0	301,266
119	Tickle Creek	LU	201				2,907	0	0	0	0	206,084	0	206,084
120	TransAlta Energy Marketing	SF	PGE-11				553,090	0	0	0	0	54,247,425	0	54,247,425
121	Turlock Irrigation District	SF	WSPP-1				56,127	0	0	0	0	2,052,684	0	2,052,684
122	Vitol Inc.	SF	WSPP-1				17,688	0	0	0	0	1,435,077	0	1,435,077
123	Volcano Solar	LU	201				1,404	0	0	0	0	98,811	0	98,811
124	VON FAMILY LTD PARTNERSHIP	LU	201				50	0	0	0	0	3,353	0	3,353
125	Warm Springs Power Enterprises	SF	WSPP-1				57,970	0	0	0	0	5,844,122	0	5,844,122
126	Warm Springs Power Enterprises	LU	WSPP-1				545,934	0	0	0	0	37,008,652	0	37,008,652
127	Warm Springs Power Enterprises	LU	WSPP-1				0	0	0	0	6,000,000	0	0	6,000,000
128	Wheatridge Solar Finance Lease	OS	WSPP-1				108,067	0	0	0	0		(k)422,098	422,098
129	Wheatridge Wind II, LLC	LU	WSPP-1				551,495	0	0	0	0	23,750,109	0	23,750,109
130	Kale Patch Solar	LU	201				3,840	0	0	0	0	313,343	0	313,343
131	Drift Creek	LU	201				12,871	0	0	0	0	483,296	0	483,296
132	Yamhill Solar	LU	Yamhill				0	0	0	0	0	111,463	0	111,463

133	[a] Load Balance Energy	OS	OATT				78,016	0	0	0	0	0	0	0
134	Country Village Estates	[d] OS	201				161	0	0	0	0	176,453	0	176,453
135	Domaine Drouhin	[e] OS	201				109	0	0	0	0	115,547	0	115,547
136	Starbuck Properties	[f] OS	201				17,295	0	0	0	0	65	0	65
137	Solar Payment Option	[g] OS	215-217				28	0	0	0	0	90,663	0	90,663
138	Tualatin Valley Water Dist	[h] OS	201				300	0	0	0	0	1,223	0	1,223
139	Green Power						0	0	0	0	0	0	[l][m]9,881,010	9,881,010
140	NVPC MONET QF Deferrals						0	0	0	0	0	0	[n](1,322,567)	(1,322,567)
141	Margin on Electric Financials						0	0	0	0	0	0	[o](55,727,009)	(55,727,009)
142	Pelton Round Butte Finance Lease 49.9%						0	0	0	0	0	0	[p]2,790,058	2,790,058
143	2021 PCAM Deferrals	AD					0	0	0	0	0	0	[q]2,466,822	2,466,822
144	REC Retirement Expense						0	0	0	0	0	0	[r]292,785	292,785
145	Carbon Allowance Expense						0	0	0	0	0	0	[s](3,929,623)	(3,929,623)
15	TOTAL						13,709,510	0	0	0	23,045,237	818,017,384	(55,562,233)	785,500,388

FERC FORM NO. 1 (ED. 12-90)

Page 326-327

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

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.

(b) Concept: StatisticalClassificationCode

The Douglas County contract expires on 12/31/2025

(c) Concept: StatisticalClassificationCode

The Okanogan County contract expires on 12/31/2025

(d) Concept: StatisticalClassificationCode

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

(e) Concept: StatisticalClassificationCode

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

(f) Concept: StatisticalClassificationCode

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

(g) Concept: StatisticalClassificationCode

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

(h) Concept: StatisticalClassificationCode

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

(i) Concept: OtherChargesOfPurchasedPower

Represents credits received from counterparty.

(j) Concept: OtherChargesOfPurchasedPower

Represents Swiss Re dual trigger option payout

(k) Concept: OtherChargesOfPurchasedPower

Wheatridge Solar Financial Lease amortization and interest

(l) Concept: OtherChargesOfPurchasedPower

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

(m) Concept: OtherChargesOfPurchasedPower

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

(n) Concept: OtherChargesOfPurchasedPower
2021 NVPC MONET QF Deferrals & Cure Payments
(o) Concept: OtherChargesOfPurchasedPower
Margin on electric financial transactions.
(p) Concept: OtherChargesOfPurchasedPower
Pelton Round Butte Finance Lease amortization and interest
(q) Concept: OtherChargesOfPurchasedPower
2021 PCAM Deferrals
(r) Concept: OtherChargesOfPurchasedPower
Expense of annual REC retirement to meet RPS compliance.
(s) Concept: OtherChargesOfPurchasedPower
Expense of carbon allowances retired to comply with California's Cap-and-Trade Program.
(t) Concept: SettlementOfPower
Represents credits received from counterparty.

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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.
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.
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 (0) 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.

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)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	BPA Power Business Line	Bonneville Power Administration	West Oregon Electric Coop Total	OLF	72	BPAT.PGE	Various	0	14,500	14,583	0		(al) 112,009	112,009
2	BPA Power Business Line	Bonneville Power Administration	Other TVI Pumps Total	OLF	72	BPAT.PGE	Various	0	5,790	5,823	0		(am) 30,326	30,326
3	BPA Power Business Line	Bonneville Power Administration	Canby PUD Total	OLF	72	BPAT.PGE	Various	0	192,715	193,813	0		(an) 437,921	437,921
4	BPA Power Business Line	Bonneville Power Administration	Columbia River PUD Total	OLF	72	BPAT.PGE	Various	0	207,498	208,681	0		(ao) 16,718	16,718
5	Pacificorp West	PacifiCorp	Portland General Electric	OLF	Exchange	PACW.PGE	Various	0	4,349	3,557	0		(ap) 266,877	266,877
6	Avangrid Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various	215	119,345	119,345	245,100	(ag) (44,255)	(aq) 86,814	287,659
7	Avangrid Renewables, LLC			(c) OS	11			0	0	0	0	147,272	0	147,272
8	BPA Power Business Line	Bonneville Power Administration	Portland General Electric	FNO	7	BPAT.PGE	Various Subs	179	88,764	88,764	203,615	(ah) (116,339)	(ar) 72,278	159,554
	BPA Power Business			(d)										

9	Line			OS	11			0	0	0	0	119,949	0	119,949
10	Calpine Energy Services	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various	2,557	1,716,467	1,716,467	2,916,560	[(ai)](2,041,146)	[(as)]1,032,478	1,907,892
11	Calpine Energy Services			[(e)] OS	11			0	0	0	0	2,129,413	0	2,129,413
12	Constellation New Energy	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various	615	405,392	405,392	701,701	[(aj)](3,822,411)	[(at)]248,328	(2,872,382)
13	Constellation New Energy			[(f)] OS	11			0	0	0	0	497,067	0	497,067
14	Shell Energy North America	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various	296	215,856	215,856	339,327	[(ak)](1,390,138)	[(au)]119,520	(931,291)
15	Shell Energy North America			[(g)] OS	11			0	0	0	0	254,801	0	254,801
16	Avista Corp	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	318,603	318,603	0	0	[(av)]1,619,665	1,619,665
17	Avista Corp	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	50	50	0	0	[(aw)]195	195
18	Avista Corp	California Independent System Operator	Bonneville Power Administration	[(h)] OS	8	Malin500	JohnDay	0	7,221	7,221	0	0	0	0
19	Avista Corp			[(i)] OS	11			0	0	0	0	311,227	0	311,227
20	Brookfield Renewable Trading and Marketing	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	0	0	0	0	[(ax)]4	4
21	Shell Energy North America	Bonneville Power Administration	Portland General Electric	LFP	7	BPAT.PGE	PGE	0	144	144	0	0	[(ay)] [(az)]420	420
22	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	397,578	397,578	0	0	[(ba)]1,160,017	1,160,017
23	Shell Energy North America	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	712,737	712,737	0	0	[(bb)]2,079,559	2,079,559
24	Shell Energy North America	Bonneville Power Administration	Portland General Electric	NF	8	BPAT.PGE	PGE	0	816	816	0	0	[(bc)]4,401	4,401
25	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	1,454	1,454	0	0	[(bd)]7,841	7,841
26	Shell Energy North America	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	5,715	5,715	0	0	[(be)]30,820	30,820
27	Shell Energy North America	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	2,855	2,855	0	0	[(bf)]15,396	15,396
28	Shell Energy North America	California Independent System Operator	Bonneville Power Administration	[(j)] OS	8	Malin500	JohnDay	0	7,805	7,805	0	0	0	0
29	Shell Energy North America			[(k)] OS	11			0	0	0	0	1,148,951	0	1,148,951
30	Dynasty Power Inc	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	8,322	8,322	0	0	[(bg)]59,783	59,783
31	Dynasty Power Inc	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	850	850	0	0	[(bh)]6,106	6,106
32	Dynasty Power Inc	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	4,703	4,703	0	0	[(bi)]33,785	33,785
33	Dynasty Power Inc			[(l)] OS	8			0	0	0	0	11,775	0	11,775
34	Constellation New Energy	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	942	942	0	0	[(bj)]3,387	3,387
35	Constellation New Energy	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	44,112	44,112	0	0	[(bk)]158,595	158,595
36	Constellation New Energy	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	22	22	0	0	[(bl)]86	86
37	Constellation New Energy	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	256	256	0	0	[(bm)]997	997

38	Constellation New Energy			[m] OS	7			0	0	0	0	38,761	0	38,761
39	Macquarie Energy LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	3,776	3,776	0	0	[bn]44,222	44,222
40	Macquarie Energy LLC	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	1,414	1,414	0	0	[bo]16,560	16,560
41	Macquarie Energy LLC			[n] OS	8			0	0	0	0	11,982	0	11,982
42	Mercuria Energy America, LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	0	0	0	0	[bp]1,326	1,326
43	Mercuria Energy America, LLC			[o] OS	8			0	0	0	0	0	0	0
44	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	43,436	43,436	0	0	[bq]106,343	106,343
45	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	22,726	22,726	0	0	[br]55,639	55,639
46	Morgan Stanley Capital Group	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	7	7	0	0	[bs]34	34
47	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	4,928	4,928	0	0	[bt]24,140	24,140
48	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	13,457	13,457	0	0	[bu]65,920	65,920
49	Morgan Stanley Capital Group	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	1,495	1,495	0	0	[bv]7,323	7,323
50	Morgan Stanley Capital Group	California Independent System Operator	Bonneville Power Administration	[p] OS	8	Malin500	JohnDay	0	62	62	0	0	0	0
51	Morgan Stanley Capital Group			[q] OS	11			0	0	0	0	98,397	0	98,397
52	Pacificorp West	Portland General Electric	Bonneville Power Administration	LFP	7	RoundButte	REDMOND	0	8,361	8,361	0	0	[bw]199,911	199,911
53	Pacificorp West	Portland General Electric	Bonneville Power Administration	NF	8	RoundButte	REDMOND	0	151	151	0	0	[bx]2,117	2,117
54	Pacificorp West			[r] OS	11			0	0	0	0	9,217	0	9,217
55	Avangrid Renewables, LLC	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	50	50	0	0	[by]328	328
56	Avangrid Renewables, LLC			[s] OS	11			0	0	0	0	53	0	53
57	Puget Sound Energy Marketing	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	625	625	0	0	[bz]2,438	2,438
58	Puget Sound Energy Marketing			[t] OS	8			0	0	0	0	1,793	0	1,793
59	Powerex Inc.	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	33,305	33,305	0	0	[ca]122,654	122,654
60	Powerex Inc.	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	1,376,076	1,376,076	0	0	[cb]5,067,752	5,067,752
61	Powerex Inc.	California Independent System Operator	Bonneville Power Administration	LFP	7	Malin500	JohnDay	0	270,806	270,806	0	0	[cc]997,312	997,312
62	Powerex Inc.	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	5,157	5,157	0	0	[cd]118,056	118,056
63	Powerex Inc.	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	2,239	2,239	0	0	[ce]51,256	51,256
64	Powerex Inc.	Bonneville Power Administration	California Independent System Operator	[u] OS	8	JohnDay	Malin500	0	100	100	0	0	0	0
65	Powerex Inc.	California Independent System Operator	Bonneville Power Administration	[v] OS	8	Malin500	JohnDay	0	540	540	0	0	0	0
66	Powerex Inc.			[w] OS	11			0	0	0	0	1,794,868	0	1,794,868

67	Rainbow Energy Marketing Corp	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	6,117	6,117	0	0	(cf)32,349	32,349
68	Rainbow Energy Marketing Corp	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	4,470	4,470	0	0	(cg)23,639	23,639
69	Rainbow Energy Marketing Corp			(x) OS	8			0	0	0	0	22,023	0	22,023
70	Seattle City Light	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	40	40	0	0	(ch)215	215
71	Seattle City Light	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	18	18	0	0	(ci)97	97
72	Seattle City Light			(y) OS	8			0	0	0	0	109	0	109
73	The Energy Authority	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	52,669	52,669	0	0	(cj)35,834	35,834
74	The Energy Authority	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	185,416	185,416	0	0	(ck)126,149	126,149
75	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	782	782	0	0	(cl)3,924	3,924
76	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	4,018	4,018	0	0	(cm)20,164	20,164
77	The Energy Authority	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	16,584	16,584	0	0	(cn)83,227	83,227
78	The Energy Authority	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	12,181	12,181	0	0	(co)61,131	61,131
79	The Energy Authority	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	20	20	0	0	(cp)100	100
80	The Energy Authority	California Independent System Operator	Bonneville Power Administration	(z) OS	8	Malin500	JohnDay	0	232	232	0	0	0	0
81	The Energy Authority			(aa) OS	11			0	0	0	0	323,956	0	323,956
82	Transalta Energy Marketing (US) Inc.	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	40	40	0	0	(cq)263	263
83	Transalta Energy Marketing (US) Inc.	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	111	111	0	0	(cr)730	730
84	Transalta Energy Marketing (US) Inc.	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	883	883	0	0	(cs)5,805	5,805
85	Transalta Energy Marketing (US) Inc.	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	3,064	3,064	0	0	(ct)20,143	20,143
86	Transalta Energy Marketing (US) Inc.			(ab) (ac) OS	8			0	0	0	0	6,549	0	6,549
87	Turlock Irrigation Dist	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	115	115	0	0	(cu)511	511
88	Turlock Irrigation Dist			(ad) OS	8			0	0	0	0	14	0	14
89	Tacoma Power	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	36	36	0	0	(cv)143	143
90	Tacoma Power	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	109	109	0	0	(cw)434	434
91	Tacoma Power			(ae) OS	8			0	0	0	0	172	0	172
92	Vitol Inc	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	177	177	0	0	(cx)1,252	1,252
93	Vitol Inc	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	450	450	0	0	(cy)3,183	3,183
94	Vitol Inc			(af) OS	8			0	0	0	0	3,981	0	3,981
95	Public Utility District No. 1 of Cowlitz County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH		0	0	0	0	(cz)161,982	161,982

96	Public Utility District No. 1 of Franklin County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH		0	0	0	0	[(da)]161,982	161,982
97	Public Utility District No. 1 of Klickitat County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH		0	0	0	0	[(db)]178,180	178,180
98	Public Utility District No. 1 of Lewis County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH		0	0	0	0	[(dc)]178,180	178,180
99	[(a)] Deferral			OS									(10,906,765)	(10,906,765)
100	[(b)] Accrual			OS								1,610,338	(2,197,371)	(587,033)
35	TOTAL							3,862	6,561,104	6,562,709	4,406,303	1,128,379	2,483,138	8,017,820

FERC FORM NO. 1 (ED. 12-90)

Page 328-330

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

Incremental revenues are deferred according to OPUC OrderNo. 22-129.

(b) Concept: PaymentByCompanyOrPublicAuthority

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.

(c) Concept: StatisticalClassificationCode

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

(d) Concept: StatisticalClassificationCode

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

(e) Concept: StatisticalClassificationCode

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

(f) Concept: StatisticalClassificationCode

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

(g) Concept: StatisticalClassificationCode

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

(h) Concept: StatisticalClassificationCode

Represents non-billed redirected MWhs.

(i) Concept: StatisticalClassificationCode

Represents non-billed redirected MWhs.

(j) Concept: StatisticalClassificationCode

Represents non-billed redirected MWhs.

(k) Concept: StatisticalClassificationCode

Represents non-billed redirected MWhs.

(l) Concept: StatisticalClassificationCode

Represents non-billed redirected MWhs.

(m) Concept: StatisticalClassificationCode

Represents non-billed redirected MWhs.

(n) Concept: StatisticalClassificationCode

Represents non-billed redirected MWhs.

(o) Concept: StatisticalClassificationCode

Represents non-billed redirected MWhs.

(p) Concept: StatisticalClassificationCode

Represents non-billed redirected MWhs.

(q) Concept: StatisticalClassificationCode

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

(r) Concept: StatisticalClassificationCode

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

(s) Concept: StatisticalClassificationCode

Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(t) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(u) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(v) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(w) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(x) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(y) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(z) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(aa) Concept: StatisticalClassificationCode
Electrical losses associated with the use of the Transmission Provider's Transmission System consistent with Section 15.7 and 28.5 of the PGE OATT and settled financially under Schedule 11.
(ab) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(ac) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(ad) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(ae) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(af) Concept: StatisticalClassificationCode
Represents non-billed redirected MWhs.
(ag) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
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.
(ah) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
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.
(ai) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
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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.
(al) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract is evergreen.
(am) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(ao) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and the Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract is evergreen.
(ap) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and PacifiCorp concerning the exchange of transmission services over agreed-upon facilities.
(aq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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.

(ar) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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.

(as) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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.

(at) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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.

(au) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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.

(av) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(aw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Includes scheduling, system control and dispatch service.

(ax) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(ay) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(az) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(ba) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(db) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(dc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
   FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm

Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin	[(a)] LFP			80,795,795			80,795,795
2	Bonneville Power Admin	OS	231,266	231,266			[(d)] 17,190,842	17,190,842
3	Bonneville Power Admin	SFP	13,530	13,530		1,345,970		1,345,970
4	Bonneville Power Admin	NF	28,155	28,155		249,839		249,839
5	Avista Corp	NF	2,288	2,288		18,339		18,339
6	Columbia River PUD	SFP	11	11		17,019		17,019
7	Eugene Water & Electric Board	[(b)] LFP	12	12		113,400		113,400
8	Idaho Power Co	NF	49,241	49,241		292,558		292,558
9	LA Dept of Water & Power	NF	36,493	36,493		357,291		357,291
10	McMinnville Water & Light	[(c)] LFP	952	952		9,927		9,927
11	Montana, State of	OS					[(e)] 1,580,922	1,580,922
12	Montague Solar	OS					[(f)] (300,000)	(300,000)
13	Morgan Stanley	NF	200	200		400		400
14	Nextera Energy Capital Holdings Inc	OS	6	6			[(g)] 1,873,939	1,873,939
15	Nevada Power Company	NF	13,359	13,359		26,409		26,409
16	NorthWestern Energy	NF	14,503	14,503		1,053,275		1,053,275
17	PacifiCorp	SFP	270,810	270,810		371,962		371,962
18	Puget Sound Energy	NF	115,856	115,856		368,643		368,643
19	Okanogan County PUD, Washington	NF	1	1		25,490		25,490
20	Seattle City Light	NF	1,275	1,275		1,959		1,959
21	UMATILLA ELECTRIC COOPERATIVE	OS					[(h)] 53,518	53,518
22	PUD NO 1 OF SNOHOMISH COUNTY	SFP	70	70		520		520
23	PacifiCorp - Linneman Substation	OS					[(i)] 112,398	112,398
	TOTAL		778,028	778,028	80,795,795	4,253,001	20,511,619	105,560,415

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode

Represents Bonneville Power Administration PTP contracts that have termination dates that range from 1/1/2022 - 1/1/2030.

(b) Concept: StatisticalClassificationCode

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

(c) Concept: StatisticalClassificationCode

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

(d) Concept: OtherChargesTransmissionOfElectricityByOthers

Represents Bonneville Power Administration Ancillary Transmission Services.

(e) Concept: OtherChargesTransmissionOfElectricityByOthers
Represents Beneficial Use Tax and Wholesale Energy Transaction Tax payments to the State of Montana for use of BPA's transmission lines.
(f) Concept: OtherChargesTransmissionOfElectricityByOthers
Represents credits received from counterparty.
(g) Concept: OtherChargesTransmissionOfElectricityByOthers
Represents Wheatridge II Reserve Charges
(h) Concept: OtherChargesTransmissionOfElectricityByOthers
Represents 2022 Annual Capacity Payments
(i) Concept: OtherChargesTransmissionOfElectricityByOthers
Represents PacifiCorp's Linneman Transmission Services.

FERC FORM NO. 1 (REV. 02-04)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,745,435
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	2,601,219
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	2,673,189
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	INVOLUNTARY SEVERANCE PROGRAM	2,096,416
7	DIRECTORS PENSION	167,560
8	DIRECTORS FEES & EXPENSES	472,900
9	DIRECTORS & OFFICERS EXPENSES	2,596,442
10	COLSTRIP- Talen Montana, LLC	719,798
11	MISC. ADMIN EXPENSES	476,841
46	TOTAL	14,549,800

FERC FORM NO. 1 (ED. 12-94)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

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 B 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 of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			60,100,949		60,100,949

2	Steam Production Plant	26,981,495	2,673,347			29,654,842
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	20,490,238	68			20,490,306
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	86,422,616	876,079			87,298,695
7	Transmission Plant	22,497,789				22,497,789
8	Distribution Plant	129,933,888	5,513			129,939,401
9	Regional Transmission and Market Operation					
10	General Plant	48,880,939	115			48,881,054
11	Common Plant-Electric					
12	TOTAL	335,206,965	3,555,122	60,100,949		398,863,036

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 year amortization of hydro licensing costs.

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	311.00-COLSTRIP	116,301	90 years	(3)%	16.79%	Lifespan - 2025	3 years
13	312.00-COLSTRIP	268,577	65 years	(3)%	16.89%	Lifespan - 2025	3 years
14	314.00-COLSTRIP	69,558	55 years	(3)%	17.3%	Lifespan - 2025	3 years
15	315.00-COLSTRIP	25,072	60 years	(3)%	17.1%	Lifespan - 2025	3 years
16	316.00-COLSTRIP	15,844	60 years	(3)%	17.27%	Lifespan - 2025	3 years
17	317.00-ARC STEAM	34,911				SQ	
18	331.00-FARADAY	17,264	105 years	(42)%	3.01%	R2.5	33 years
19	331.00-NORTH FORK	9,359	105 years	(71)%	2.99%	R2.5	34 years
20	331.00-OAK GROVE	24,877	105 years	(36)%	3%	R2.5	33 years
21	331.00-PELTON	5,302	105 years	(89)%	3.05%	R2.5	33 years
22	331.00-RIVER MILL	7,501	105 years	(87)%	3.04%	R2.5	33 years
23	331.00-ROUND BUTTE	9,448	105 years	(84)%	3.03%	R2.5	33 years
24	331.00-SULLIVAN	19,612	105 years	(29)%	6.56%	R2.5	15 years
25	332.00-FARADAY	34,373	105 years	(42)%	2.96%	R3	34 years
26	332.00-NORTH FORK	85,626	105 years	(71)%	2.91%	R3	34 years
27	332.00-OAK GROVE	27,259	105 years	(36)%	2.92%	R3	34 years
28	332.00-PELTON	8,016	105 years	(89)%	3.13%	R3	32 years
29	332.00-RIVER MILL	58,746	105 years	(87)%	2.92%	R3	34 years
30	332.00-ROUND BUTTE	84,413	105 years	(84)%	2.94%	R3	34 years
31	332.00-SULLIVAN	31,499	105 years	(29)%	6.51%	R3	15 years
32	333.00-FARADAY	6,737	95 years	(42)%	3.25%	S0.5	31 years
33	333.00-NORTH FORK	11,388	95 years	(71)%	3.16%	S0.5	32 years
34	333.00-OAK GROVE	15,837	95 years	(36)%	3.12%	S0.5	32 years
35	333.00-PELTON	3,944	95 years	(89)%	3.33%	S0.5	30 years
36	333.00-RIVER MILL	10,052	95 years	(87)%	3.2%	S0.5	31 years
37	333.00-ROUND	18,095	95 years	(84)%	3.14%	S0.5	32 years

	BUTTE						
38	333.00-SULLIVAN	10,215	95 years	(29)%	6.7%	S0.5	15 years
39	334.00-FARADAY	4,594	60 years	(42)%	3.67%	R2	27 years
40	334.00-NORTH FORK	1,017	60 years	(71)%	3.62%	R2	28 years
41	334.00-OAK GROVE	7,438	60 years	(36)%	3.55%	R2	28 years
42	334.00-PELTON	9,281	60 years	(89)%	3.45%	R2	29 years
43	334.00-RIVER MILL	5,697	60 years	(87)%	3.74%	R2	27 years
44	334.00-ROUND BUTTE	2,427	60 years	(84)%	3.56%	R2	28 years
45	334.00-SULLIVAN	4,185	60 years	(29)%	6.83%	R2	15 years
46	335.00-FARADAY	984	55 years	(42)%	4.83%	R0.5	21 years
47	335.00-NORTH FORK	888	55 years	(71)%	4.29%	R0.5	23 years
48	335.00-OAK GROVE	517	55 years	(36)%	4.15%	R0.5	24 years
49	335.00-PELTON	630	55 years	(89)%	4.75%	R0.5	21 years
50	335.00-RIVER MILL	408	55 years	(87)%	5.43%	R0.5	18 years
51	335.00-ROUND BUTTE	854	55 years	(84)%	4.3%	R0.5	23 years
52	335.00-SULLIVAN	109	55 years	(29)%	7.2%	R0.5	14 years
53	336.00-FARADAY	2,267	80 years	(42)%	3.5%	R1	29 years
54	336.00-NORTH FORK	2,838	80 years	(71)%	3.49%	R1	29 years
55	336.00-OAK GROVE	6,767	80 years	(36)%	3.66%	R1	27 years
56	336.00-PELTON	3,513	80 years	(89)%	3.76%	R1	27 years
57	336.00-RIVER MILL	476	80 years	(87)%	3.39%	R1	30 years
58	336.00-ROUND BUTTE	1,380	80 years	(84)%	3.5%	R1	29 years
59	337.00-ARC HYDRO	5				SQ	
60	341.00-BEAVER - CT	37,797	70 years	(7)%	6.61%	R3	15 years
61	341.00-COYOTE SPRINGS - CT	11,586	70 years	(2)%	5.08%	R3	20 years
62	341.00-PORT WESTWARD - CT	43,073	70 years	(3)%	3.47%	R3	29 years
63	341.00-PORT WESTWARD II	42,472	70 years	(3)%	2.56%	R3	39 years
64	341.00-CARTY	87,680	70 years	(4)%	2.49%	R3	40 years
65	341.00-KB PIPELINE	0	70 years	(20)%	6.52%	R3	15 years
66	341.01-BIGLOW CANYON WIND FARM	34,351	40 years	(5)%	3.63%	R4	28 years
67	341.01-TUCANNON RIVER WIND FARM	18,855	40 years	(4)%	2.91%	R4	34 years
68	341.00-WHEATRIDGE WIND	3,441	40 years	(3)%	3.47%	R4	28 years
69	342.00-BEAVER - CT	61,123	50 years	(7)%	6.99%	R3	14 years
70	342.00-COYOTE SPRINGS - CT	36,864	50 years	(2)%	5.56%	R3	18 years
71	342.00-PORT WESTWARD - CT	10,330	50 years	(3)%	3.74%	R3	27 years
72	342.00-PORT WESTWARD II	7,511	50 years	(3)%	2.68%	R3	37 years
73	342.00-CARTY	7,478	50 years	(4)%	2.63%	R3	38 years

74	342.00-KB PIPELINE	20,951	50 years	(15)%	7.04%	R3	14 years	
75	344.00-BEAVER - CT	147,993	45 years	(7)%	7.35%	R1.5	14 years	
76	344.00-COYOTE SPRINGS - CT	142,439	45 years	(2)%	5.91%	R1.5	17 years	
77	344.00-PORT WESTWARD - CT	210,541	45 years	(3)%	4.41%	R1.5	23 years	
78	344.00-PORT WESTWARD II	221,263	45 years	(3)%	3.01%	R1.5	33 years	
79	344.00-CARTY	396,079	45 years	(4)%	2.92%	R1.5	34 years	
80	344.01-BIGLOW CANYON WIND FARM	877,373	30 years	(5)%	5.64%	R3	18 years	
81	344.01-TUCANNON RIVER WIND FARM	448,808	30 years	(4)%	4.05%	R3	25 years	
82	344.00-WHEATRIDGE WIND	120,419	30 years	(3)%	3.82%	R3	28 years	
83	344.02-GENERATORS - SOLAR	1,324	20 years	(2)%	7.28%	L2.5	14 years	
84	345.00-DISPATCH GENERATION	15,067	50 years	(5)%	2.84%	R2.5	35 years	
85	345.00-BEAVER - CT	26,763	50 years	(7)%	6.86%	R2.5	15 years	
86	345.00-COYOTE SPRINGS - CT	12,197	50 years	(2)%	5.66%	R2.5	18 years	
87	345.00-PORT WESTWARD - CT	9,740	50 years	(3)%	3.91%	R2.5	26 years	
88	345.00-PORT WESTWARD II	20,931	50 years	(3)%	2.78%	R2.5	36 years	
89	345.01-BIGLOW CANYON WIND FARM	27,197	30 years	(5)%	5.5%	S2.5	18 years	
90	345.01-TUCANNON RIVER WIND FARM	14,261	30 years	(4)%	4.07%	S2.5	25 years	
91	345.00-WHEATRIDGE WIND	19,716	30 years	(3)%	3.83%	S2.5	28 years	
92	346.00-BEAVER - CT	6,460	60 years	(7)%	6.85%	R2.5	15 years	
93	346.00-COYOTE SPRINGS - CT	2,929	60 years	(2)%	5.21%	R2.5	19 years	
94	346.00-PORT WESTWARD - CT	3,430	60 years	(3)%	3.67%	R2.5	27 years	
95	346.00-PORT WESTWARD II	5,630	60 years	(3)%	2.66%	R2.5	38 years	
96	346.00-CARTY	28,015	60 years	(4)%	2.58%	R2.5	39 years	
97	346.00-KB PIPELINE	191	60 years	(5)%	6.79%	R2.5	15 years	
98	346.01-BIGLOW CANYON WIND FARM	1,385	45 years	(5)%	3.55%	R2.5	28 years	
99	346.01-TUCANNON RIVER WIND FARM	535	45 years	(4)%	2.75%	R2.5	36 years	
100	346.00-WHEATRIDGE WIND	1,095	40 years	(3)%	3.63%	R2.5	28 years	
101	347.00-ARC OTHER PRODUCTION	26,802				SQ		
102	[(a)] 348.00-ENERGY STORAGE PILOT	6,332	10 years	(5)%	10%	SQ	9 years	
103	352.00-STRUCTURES AND IMPROVEMENTS	30,235	70 years	(20)%	2.17%	R2.5	46 years	

104	353.00-STATION EQUIPMENT	602,638	62 years	(20)%	2.48%	R2	40 years
105	354.00-TOWERS AND FIXTURES	52,987	70 years	(10)%	3.57%	S3	28 years
106	355.00-POLES AND FIXTURES	158,782	52 years	(50)%	3.24%	S0	31 years
107	356.00-OVERHEAD CONDUCTORS AND DEVICES	253,069	65 years	(20)%	2.14%	R2.5	47 years
108	359.00-ROADS AND TRAILS	286	65 years	0%	3.43%	R3	29 years
109	359.10-ARC TRANSMISSION	34				SQ	
110	361.00-STRUCTURES AND IMPROVEMENTS	57,653	70 years	(25)%	2.3%	R2	44 years
111	362.00-STATION EQUIPMENT	740,966	59 years	(20)%	2.92%	S0	34 years
112	363.00-STORAGE BATTERY	399	15 years	(5)%	13.45%	L3	7 years
113	(b) 363.00-ENERGY STORAGE PILOT	1,178	10 years	(5)%	10%	SQ	
114	364.00-POLES, TOWERS AND FIXTURES	618,143	50 years	(45)%	3.85%	R0.5	26 years
115	365.00-OVERHEAD CONDUCTORS AND DEVICES	814,777	60 years	(65)%	2.89%	R1	35 years
116	366.00-UNDERGROUND CONDUIT	33,304	85 years	(10)%	1.55%	R4	65 years
117	367.00-UNDERGROUND CONDUCTORS AND DEVICES	1,003,224	65 years	(55)%	2.32%	S1	43 years
118	368.00-LINE TRANSFORMERS	539,658	52 years	(10)%	2.85%	R2.5	35 years
119	369.01-SERVICES - OVERHEAD	122,047	55 years	(30)%	2.98%	R1.5	34 years
120	369.03-SERVICES - UNDERGROUND	460,025	55 years	(30)%	2.45%	R4	41 years
121	370.00-METERS	6,727	28 years	(2)%	6.39%	R2	16 years
122	370.01-METERS - AMI	211,619	20 years	(2)%	8.25%	R2.5	12 years
123	370.02-METERS - RETAINED	6,990	16 years	(2)%	14.6%	L0.5	7 years
124	371.00-INSTALLATIONS ON CUSTOMERS' PREMISES	6,112	30 years	0%	4.01%	R4	25 years
125	373.01-CIRCUITS - OTHER	27,261	40 years	(25)%	4.37%	L2.5	23 years
126	373.02-FIXTURES, ORNAMENTAL POSTS AND DEVICES	134,883	28 years	(25)%	6.02%	L1	17 years
127	373.07-SENTINEL LIGHTING EQUIPMENT	9,316	30 years	(25)%	6.18%	L0.5	16 years
128	374.00-ARC DISTRIBUTION	477				SQ	
	390.00-STRUCTURES						

129	AND IMPROVEMENTS	137,552	42 years	(5)%	4.35%	R0.5	23 years
130	390.00-INTEGRATED OPERATIONS CENTER	147,155	60 years	(5)%	2.02%	R1.5	50 years
131	390.10-CSS	43		0%	11.18%	Lifespan - 2028	5 years
132	390.10-ERC TUALATIN	1,907		0%	11.11%	Lifespan - 2028	5 years
133	390.10-WILSONVILLE	605		0%	49.99%	Lifespan - 2023	1 year
134	390.10-WTC	28,726		0%	4.21%	Lifespan - 2043	20 years
135	391.10-FURNITURE AND EQUIPMENT	34,256	15 years	0%	10.09%	SQ	10 years
136	391.20-COMPUTERS AND EQUIPMENT	94,337	5 years	0%	37.34%	SQ	3 years
137	391.00-COLSTRIP	72	15 years	0%	32.4324%	Lifespan - 2025	3 years
138	392.04-HEAVY DUTY TRUCKS	27,310	20 years	15%	8.57%	S0	12 years
139	392.04-COLSTRIP	109	20 years	15%	38.1558%	Lifespan - 2025	3 years
140	392.05-MEDIUM DUTY TRUCKS	42,130	15 years	15%	8.65%	S2	12 years
141	392.05-COLSTRIP	69	15 years	15%	38.1558%	Lifespan - 2025	3 years
142	392.06-LIGHT DUTY TRUCKS	12,369	13 years	15%	11.98%	L2.5	8 years
143	392.06-COLSTRIP	130	13 years	15%	38.1558%	Lifespan - 2025	3 years
144	392.08-TRAILERS	7,572	30 years	15%	5.82%	S0	17 years
145	392.08-COLSTRIP	14	30 years	15%	38.1558%	Lifespan - 2025	3 years
146	392.09-AUTOS	3,265	12 years	15%	12.68%	S1.5	8 years
147	392.09-COLSTRIP	49	12 years	15%	38.1558%	Lifespan - 2025	3 years
148	392.10-HELICOPTER	2,867	20 years	15%	11.59%	S4	9 years
149	393.00-STORES EQUIPMENT	4,181	20 years	0%	7.78%	SQ	13 years
150	394.00-TOOLS, SHOP AND GARAGE EQUIPMENT	24,373	20 years	0%	6.41%	SQ	16 years
151	394.00-COLSTRIP	109	20 years	0%	32.4324%	Lifespan - 2025	3 years
152	395.00-LABORATORY EQUIPMENT	13,079	15 years	0%	18.75%	SQ	5 years
153	396.01-MAN LIFT	27,643	14 years	10%	12.01%	S1.5	8 years
154	396.02-DIGGER	6,178	15 years	10%	19.81%	S2	5 years
155	396.03-CRANE	3,714	23 years	10%	7.26%	S2.5	14 years
156	396.03-COLSTRIP	47	23 years	10%	36.036%	Lifespan - 2025	3 years
157	396.07-CONSTRUCTION EQUIPMENT	7,733	20 years	10%	8.81%	L2	11 years
158	396.07-COLSTRIP	126	20 years	10%	36.036%	Lifespan - 2025	3 years
159	397.01-LINE EQUIPMENT	38,429	15 years	0%	8.56%	SQ	12 years
160	397.03-RADIO, MICROWAVE AND TERMINAL EQUIPMENT	224,305	15 years	0%	10.1%	SQ	10 years
161	397.03-COLSTRIP	3,993	15 years	0%	32.4324%	Lifespan - 2025	3 years

162	397.06-MOBILE RADIO EQUIPMENT	25,155	15 years	0%	8.09%	SQ	12 years
163	397.07-TELEPHONE EQUIPMENT	1,045	15 years	0%	12.79%	SQ	8 years
164	398.00-MISCELLANEOUS EQUIPMENT	2,252	20 years	0%	5.8%	SQ	17 years
165	399.00-ARC GENERAL	65				SQ	
166	Plant Balances as of 12/31/2022. Except for certain assets related to energy storage equipment, depreciation parameters per Order 21-463 in OPUC Docket UM-2152. Rates effective as of 5/9/2022.						

FERC FORM NO. 1 (REV. 12-03)

Page 336-337

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

Depreciation parameters per Order 18-290 in OPUC Docket UM-1856

(b) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

Depreciation parameters per Order 18-290 in OPUC Docket UM-1856

FERC FORM NO. 1 (REV. 12-03)

Page 336-337

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
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 columns (f), (g), and (h), expenses incurred during the 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						
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 Expenses for Current Year (d)	Deferred in Account 182.3 at Beginning of Year (e)	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)
1	FERC:											
2	Docket RM06-16		60,634	60,634				60,634				
3	Docket ER22-233		(425,145)	[a](425,145)				(425,145)				
4	FERC matters less than $25,0000		3,054	3,054				3,054				
5	OPUC:											
6	OPUC Docket UM 2111		49,971	49,971				49,971				
7	OPUC Docket UE 394		334,077	334,077				334,077				

8	OPUC Docket UM 2032		83,612	83,612				83,612				
9	OPUC Docket UE 408		2,418	2,418				2,418				
10	OPUC Docket UM 1971		84,515	84,515				84,515				
11	OPUC Docket AR 631		139,681	139,681				139,681				
12	OPUC Docket UM 2011		12,976	12,976				12,976				
13	OPUC Docket UM 2074		90,543	90,543				90,543				
14	OPUC Docket UM 1728		10,170	10,170				10,170				
15	OPUC matters less than $25,000		174,660	174,660				174,660				
16	Unassigned Non-Doc Matters		616,441	616,441				616,441				
46	TOTAL	0	1,237,607	1,237,607	0			1,237,607	0		0	0

FERC FORM NO. 1 (ED. 12-96)

Page 350-351

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: RegulatoryCommissionExpensesAmount

Credit balance due to reversal of cost accrued in error during 2021.

FERC FORM NO. 1 (ED. 12-96)

Page 350-351

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 and 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 and 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 and 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 and D Performed Externally:
      1. Research Support to the electrical Research Council or the Electric Power Research Institute
      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 and 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 and 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 and 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 and 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.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	A(6)	Electric R, D & D Performed Internally - Other	12,538		930.2	12,538	
2	B(1)	Electric R, D & D Performed Externally		2,225,680	930.2	2,225,680	
3	B(4)	Electric R, D & D Performed Externally		427,906	930.2	427,906	

FERC FORM NO. 1 (ED. 12-87)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	31,804,638		
4	Transmission	10,904,951		
5	Regional Market			
6	Distribution	51,553,822		
7	Customer Accounts	23,648,772		
8	Customer Service and Informational	10,080,229		
9	Sales			
10	Administrative and General	83,406,697		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	211,399,109		
12	Maintenance			
13	Production	12,367,986		
14	Transmission	964,692		
15	Regional Market			
16	Distribution	31,799,717		
17	Administrative and General	1,482,562		
18	TOTAL Maintenance (Total of lines 13 thru 17)	46,614,957		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	44,172,624		
21	Transmission (Enter Total of lines 4 and 14)	11,869,643		

22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	83,353,539		
24	Customer Accounts (Transcribe from line 7)	23,648,772		
25	Customer Service and Informational (Transcribe from line 8)	10,080,229		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	84,889,259		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	258,014,066	22,965,573	280,979,639
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			
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			0
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	258,014,066	22,965,573	280,979,639
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	77,028,541	29,094,061	106,122,602
69	Gas Plant			0
70	Other (provide details in footnote):			0
71	TOTAL Construction (Total of lines 68 thru 70)	77,028,541	29,094,061	106,122,602
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,927,681	46,148	1,973,829
74	Gas Plant			0
75	Other (provide details in footnote):			0
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,927,681	46,148	1,973,829
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	1,721,656	105,885	1,827,541
79	Co-Owner Shares of Generating Facilities	4,580,658	525,506	5,106,164
80	Other	8,109,856	461,861	8,571,717
81	Payroll Allocated	53,199,034	(53,199,034)	0
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	67,611,204	(52,105,782)	15,505,422
96	TOTAL SALARIES AND WAGES	404,581,492	0	404,581,492

FERC FORM NO. 1 (ED. 12-88)

Page 354-355

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	1,711,606	3,745,700	11,452,956	[a]18,266,894
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	31,921,724	32,515,071	43,806,776	[b]135,955,680
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
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41					
42					
43					
44					
45					
46	TOTAL	33,633,330	36,260,771	55,259,732	154,222,574

FERC FORM NO. 1 (NEW. 12-05)

Page 397

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

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

(b) Concept: IsoOrRtoSettlementsEnergyNetSales

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

FERC FORM NO. 1 (NEW. 12-05)

Page 397

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			**Amount Sold for the Year**		
		Usage - Related Billing Determinant			**Usage - Related Billing Determinant**		
Line No.	**Type of Ancillary Service (a)**	**Number of Units (b)**	**Unit of Measure (c)**	**Dollar (d)**	**Number of Units (e)**	**Unit of Measure (f)**	**Dollars (g)**
1	Scheduling, System Control and Dispatch	231,266	MWH	16,284,690	1,884,858	MWH	1,051,214
2	Reactive Supply and Voltage				4,113	MWH	153,893
3	Regulation and Frequency Response				3,862	MWH	336,129
4	Energy Imbalance	[a]118,489	MWH	[b]9,989,835	[c]42,411		[d]2,575,547
5	Operating Reserve - Spinning				[e]3,862	MW	387,841
6	Operating Reserve - Supplement				[f]3,862	MW	387,841
7	Other						
8	Total (Lines 1 thru 7)	349,755		26,274,525	1,942,968		4,892,465

FERC FORM NO. 1 (New 2-04)

Page 398

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits
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.
(b) Concept: AncillaryServicesPurchasedAmount
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.
(c) Concept: AncillaryServicesSoldNumberOfUnits
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.
(d) Concept: AncillaryServicesSoldAmount
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.
(e) Concept: AncillaryServicesSoldNumberOfUnits
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.
(f) Concept: AncillaryServicesSoldNumberOfUnits
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: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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.

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)
	NAME OF SYSTEM: PGE-1									
1	January	5,414	26	9	3,152	294	2,661	72	2,302	11
2	February	5,246	21	20	2,913	281	2,661	67	2,004	155
3	March	4,915	10	8	2,996	299	2,661	74	2,002	44
4	Total for Quarter 1				9,061	874	7,983	213	6,308	210
5	April	4,517	1	9	2,533	287	2,661	59	2,002	50
6	May	4,374	27	15	1,977	288	2,661	64	1,802	107
7	June	5,296	27	20	3,315	327	2,661	80	2,327	46
8	Total for Quarter 2				7,825	902	7,983	203	6,131	203
9	July	5,961	29	17	3,865	356	2,661	92	3,090	311
10	August	5,834	17	19	3,626	356	2,661	87	2,627	155
11	September	5,385	7	16	2,866	350	2,661	60	2,427	346
12	Total for Quarter 3				10,357	1,062	7,983	239	8,144	812
13	October	4,580	13	19	2,475	322	2,661	59	2,212	143
14	November	4,955	2	19	2,734	282	2,661	60	2,352	132
15	December	5,361	22	19	3,807	270	2,661	92	2,552	42
16	Total for Quarter 4				9,016	874	7,983	211	7,116	317
17	Total				36,259	3,712	31,932	866	27,699	1,542

Name of Respondent:	This report is:		

Portland General Electric Company	(1) An Original (2) A Resubmission	Date of Report: 2023-04-14	Year/Period of Report End of: 2022/ Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	18,905,061
3	Steam	2,185,619	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,745,270
5	Hydro-Conventional	1,026,718	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	28,568
7	Other	[(a)] 9,968,608	27	Total Energy Losses	1,209,951
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	13,180,945	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	26,888,850
10	Purchases (other than for Energy Storage)	13,709,510			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	6,561,104			
17	Delivered	6,562,709			
18	Net Transmission for Other (Line 16 minus line 17)	(1,605)			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	26,888,850			

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 2023-04-14	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: OtherEnergyGeneration

In addition to the generation from the Beaver, Port Westward 1, Port Westward 2, Coyote Springs, and Carty generation plants (as shown on page 403), and generation from PGE's solar generation facilities (as shown on page 410), other generation includes 1,762,687 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 1,772,060 megawatt hours.

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

In-service production cost at 12/31/2022: $942,141,962

Total installed capacity: 450 megawatts

Operations and maintenance expense for 2022: $12,826,376

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

In-service production cost at 12/31/2022: $489,354,048

Total installed capacity: 267 megawatts

Operations and maintenance expense for 2022: $8,455,226

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

In-service production cost at 12/31/2022: $147,437,264

Total installed capacity: 100 megawatts

Operations and maintenance expense for 2022: $2,994,556

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

MONTHLY PEAKS AND OUTPUT

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

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: PGE-1					
29	January	2,411,024	554,889	3,424	26	9
30	February	2,220,433	601,970	3,625	23	8
31	March	2,139,662	501,487	3,273	10	8
32	April	1,949,524	392,651	3,115	13	9
33	May	2,053,673	573,948	2,803	9	9
34	June	2,047,353	591,006	3,801	27	18
35	July	2,403,919	663,922	4,255	29	18
36	August	2,623,173	778,893	4,020	30	18
37	September	2,305,492	751,838	3,553	1	18
38	October	2,020,088	471,668	3,013	2	18
39	November	2,206,810	434,095	3,452	29	18
40	December	2,509,304	516,314	4,113	22	18
41	Total	26,890,455	6,832,681			

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

Steam Electric Generating Plant Statistics

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.
9. Items under Cost of Plant are based on USofA 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.

Line No.	Item (a)	Plant Name: Beaver	Plant Name: Carty	Plant Name: [a] Colstrip	Plant Name: Coyote Springs	Plant Name: Port Westward 1	Plant Name: Port Westward 2
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas & Steam Turbine	Gas & Steam Turbine	Steam	Gas & Steam Turbine	Gas & Steam Turbine	Reciprocating Engine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor	Outdoor		Outdoor	Outdoor	Outdoor
3	Year Originally Constructed	1974	2016		1995	2007	2014
4	Year Last Unit was Installed	2001	2016		1995	2007	2014
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	573.2	503.1	311.2	296	483.3	225.1
6	Net Peak Demand on Plant - MW (60 minutes)	519	478		283	420	224
7	Plant Hours Connected to Load	4,322	7,528		5,820	6,484	5,246
8	Net Continuous Plant Capability (Megawatts)						
9	When Not Limited by Condenser Water	533			270	421	225
10	When Limited by Condenser Water						
11	Average Number of Employees	43	29		30	30	
12	Net Generation, Exclusive of Plant Use - kWh	869,279,000	2,994,478,000	2,189,226,000	1,364,411,000	2,320,914,000	693,269,000
13	Cost of Plant: Land and Land Rights	24,473		3,328,862		24,473	
14	Structures and Improvements	37,778,998	87,679,537	116,300,825	11,585,593	43,091,588	42,471,958
15	Equipment Costs	252,910,295	431,572,027	379,051,142	194,429,249	244,612,209	261,667,147
16	Asset Retirement Costs	2,941,318	10,434,861	34,911,263	113,193	231,072	647,461
17	Total cost (total 13 thru 20)	293,655,084	529,686,425	533,592,092	206,128,035	287,959,342	304,786,566
18	Cost per KW of Installed Capacity (line 17/5) Including	512.3082	1,052.8452	1,714.6275	696.3785	595.819	1,354.0052
19	Production Expenses: Oper, Supv, & Engr	500,522	259,401	62,796	233,059	908,288	110,998
20	Fuel	60,143,927	107,695,847	44,842,017	48,139,255	130,910,570	48,612,183
21	Coolants and Water (Nuclear Plants Only)						
22	Steam Expenses			1,828,295			
23	Steam From Other Sources						
24	Steam Transferred (Cr)						
25	Electric Expenses	2,037,143	4,301,614		1,501,721	2,758,373	2,092,795
26	Misc Steam (or Nuclear) Power Expenses	1,682,091	1,435,906	3,358,834	1,194,837	1,689,680	395,794
27	Rents	217,035			93,378	28,586	33,347
28	Allowances						
29	Maintenance Supervision and Engineering	2,040,895	324,287	651,732	39,685	463,591	72,511
30	Maintenance of Structures	164,589	22,865	986,889	68,109	142,685	32,917
31	Maintenance of Boiler (or reactor) Plant			6,560,047			
32	Maintenance of Electric Plant	3,409,085	7,418,919	920,669	6,668,850	7,106,001	2,166,101
33	Maintenance of Misc Steam (or Nuclear) Plant	397,198	259,846	598,588	34,706	112,690	65,976
34	Total Production Expenses	70,592,485	121,718,685	59,809,867	57,973,600	144,120,464	53,582,622
35	Expenses per Net kWh	0.0812	0.0406	0.0273	0.0425	0.0621	0.0773

35	Plant Name	Beaver	Beaver	Carty	Coyote Springs	Port Westward 1	Port Westward 2
36	Fuel Kind	Gas	Oil	Gas	Gas	Gas	Gas
37	Fuel Unit	Mcf's	Barrels	Mcf's	Mcf's	Mcf's	Mcf's

38	Quantity (Units) of Fuel Burned	8,708,640	2,549.9048	20,173,642	9,941,281	15,994,716	5,919,118
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,019,000	138,690	1,019,000	1,019,000	1,019,000	1,019,000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	12.387	156.778	4.423	4.243	8.581	8.754
41	Average Cost of Fuel per Unit Burned	6.876	103.756	5.338	4.842	8.185	8.213
42	Average Cost of Fuel Burned per Million BTU	6.745	17.846	5.237	4.75	8.029	8.057
43	Average Cost of Fuel Burned per kWh Net Gen	0.069	0	0.036	0.035	0.056	0.07
44	Average BTU per kWh Net Generation	(b) 10,229.354	(c) 0	6,867.429	7,427.252	7,025.035	8,703.345

FERC FORM NO. 1 (REV. 12-03)

Page 402-403

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: PlantName

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

(b) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration

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.

(c) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration

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.

FERC FORM NO. 1 (REV. 12-03)

Page 402-403

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

Hydroelectric Generating Plant Statistics

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.
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.

Line No.	Item (a)	FERC Licensed Project No. 2195 Plant Name: Faraday	FERC Licensed Project No. 2195 Plant Name: North Fork	FERC Licensed Project No. 2195 Plant Name: Oak Grove	FERC Licensed Project No. 2030 Plant Name: (a) Pelton	FERC Licensed Project No. 2030 Plant Name: (b) Pelton (PGE%)	FERC Licensed Project No. 2195 Plant Name: River Mill	FERC Licensed Project No. 2030 Plant Name: (c) Round Butte	FERC Licensed Project No. 2030 Plant Name: (d) Round Butte (PGE%)	FERC Licensed Project No. 2233 Plant Name: Sullivan
1	Kind of Plant (Run-of-River or Storage)	Run-of River;Storage	Run-of River	Run-of River	Storage	Storage	Run-of River	Storage	Storage	Run-of River
2	Plant Construction type (Conventional or Outdoor)	Conventional; Outdoor	Outdoor	Conventional	Outdoor	Outdoor	Conventional	Conventional	Conventional	Conventional
3	Year Originally Constructed	1907	1958	1924	1957	1957	1911	1964	1964	1895
4	Year Last Unit was Installed	1958	1958	1931	1958	1958	1952	1964	1964	1953
5	Total installed cap (Gen name plate Rating in MW)	36.8	50.3	51	110.2	55.1	20.6	372.5	186.3	15.4
6	Net Peak Demand on Plant-Megawatts (60 minutes)	(e)	56	36	90		27	217		18
7	Plant Hours Connect to Load	(f)	8,686	2,820	8,726		8,755	8,754		8,684
8	**Net Plant Capability (in megawatts)**									
9	(a) Under Most Favorable Oper Conditions	46	58	44	110		25	345		18

10	(b) Under the Most Adverse Oper Conditions	5	7	19	60		4	192		7
11	Average Number of Employees	52		1	[(g)]			[(h)]40		1
12	Net Generation, Exclusive of Plant Use - kWh	[(i)](4,000)	202,153,000	46,815,000	333,109,378	166,588,000	106,568,000	758,980,204	379,566,000	125,032,000
13	**Cost of Plant**									
14	Land and Land Rights	33,434	377,100	9,457	3,681,653	1,841,302	86,408	3,699,286	1,891,263	572,077
15	Structures and Improvements	17,263,884	9,359,102	24,877,018	10,553,752	5,301,552	7,500,843	18,801,764	9,447,633	19,611,993
16	Reservoirs, Dams, and Waterways	34,372,807	85,626,155	27,258,896	15,511,814	8,016,063	58,745,880	163,921,399	84,413,122	31,499,172
17	Equipment Costs	12,314,931	13,289,180	23,792,158	27,079,530	13,856,205	16,161,634	42,243,114	[(j)]188,670,622	14,509,822
18	Roads, Railroads, and Bridges	2,266,997	2,837,601	6,767,403	6,436,021	3,512,892	475,899	2,566,802	1,379,643	
19	Asset Retirement Costs	90	6	2,122	52	52	64	164	164	2,630
20	Total cost (total 13 thru 20)	66,252,143	111,489,144	82,707,054	63,262,822	32,528,066	82,970,728	231,232,529	285,802,447	66,195,694
21	Cost per KW of Installed Capacity (line 20 / 5)	1,800.33	2,216.484	1,621.7069	574.0728	590.346	4,027.7052	620.7585	1,534.0979	4,298.4217
22	**Production Expenses**									
23	Operation Supervision and Engineering	95,305	13,346	17,658	252,351	117,286	11,172	358,823	193,744	3,786
24	Water for Power	78,179	61,441	83,317	211,915	83,081	50,841	360,794	203,331	42,099
25	Hydraulic Expenses	1,380,355	381,096	1,477,233	3,104,569	1,648,152	294,359	3,417,994	1,637,928	253,087
26	Electric Expenses	764,531	312,194	272,879	419,893	215,260	80,296	489,769	239,662	189,361
27	Misc Hydraulic Power Generation Expenses	1,779,981	328,064	351,709	818,968	398,210	141,602	1,051,442	537,182	221,503
28	Rents	190,635	118,148	824,465	15,407	4,262		34,136	20,514	
29	Maintenance Supervision and Engineering	357,667	2,524	83,229	2,367	1,401	751	6,673	5,492	2,484
30	Maintenance of Structures	3,850			3,101			3,790		
31	Maintenance of Reservoirs, Dams, and Waterways	64,350	80,000	237,429	72,790	16,368	10,413	178,026	109,066	312,379
32	Maintenance of Electric Plant	196,197	113,587	816,484	222,957	58,551	160,281	507,882	306,942	192,881
33	Maintenance of Misc Hydraulic Plant	1,000,224	277,690	489,151	271,895	132,490	89,765	347,809	177,425	81,906
34	Total Production Expenses (total 23 thru 33)	5,911,274	1,688,090	4,653,554	5,396,213	2,675,061	839,480	6,757,138	3,431,286	1,299,486
35	Expenses per net kWh	(1,477.8185)	0.0084	0.0994	0.0162	0.0161	0.0079	0.0089	0.009	0.0104

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: PlantName

Respondent is the principal owner (50.01% interest) and operator of the 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.

(b) Concept: PlantName

Jointly owned. Reported here are respondents 50.01% share of installed capacity, cost of plant, net generation and production expenses.

(c) Concept: PlantName

Respondent is the principal owner (50.01% interest) and operator of the 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.

(d) Concept: PlantName

Jointly owned. Reported here are respondents 50.01% share of installed capacity, cost of plant, net generation and production expenses.

(e) Concept: NetPeakDemandOnPlant

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.
(f) Concept: PlantHoursConnectedToLoad
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.
(g) Concept: PlantAverageNumberOfEmployees
Pelton employees are reported at the Round Butte Location. Pelton and Round Butte are considered one department, are in close geographic proximity and share one FERC license. Employees are assigned to projects between both locations as needed.
(h) Concept: PlantAverageNumberOfEmployees
Pelton employees are reported at the Round Butte Location. Pelton and Round Butte are considered one department, are in close geographic proximity and share one FERC license. Employees are assigned to projects between both locations as needed.
(i) Concept: NetGenerationExcludingPlantUse
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.
(j) Concept: EquipmentCostsHydroelectricProduction
Includes recognition of failed sale leaseback of 16.66% of plant ownership as well as regular activities of capitalized lease assets.

FERC FORM NO. 1 (REV. 12-03)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
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.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
1	Maclaren	1999	0.5	0.4		133,799	267,598			46,078	diesel-low	3,043	Other
2	Oregon Military Dept/Anderson Readiness Center	2001	1.6	1.6	17	192,125	120,078		9,497	52,578	diesel-low	2,643	Other
3	US Bank Corp Columbia Center	2001	6.4	6.2	142	488,057	76,259			39,628	diesel-low	3,043	Other
4	Portland State University	2004	2.8	2.8	22	261,802	93,501			62,756	diesel-low	3,043	Other
5	Oregon Military Joint Forces HQ	2005	1.6	1.6	13	191,439	119,649		11,342	26,558	diesel-low	2,699	Other
6	Stimson Lumber	2005	0.57	0.51	5	159,546	279,905		2,376	8,006	diesel-low	2,821	Other
7	Flexential (Formerly ViaWest/Fortix)	2005	14	12.4	148	629,125	44,938		61,622	83,939	diesel-low	3,081	Other
8	Skyline	2005	2	1.8	67	201,526	100,763		3,838	15,107	diesel-low	2,365	Other
9	Tri-Quint	2005	0.6	0.54		109,968	183,280			14,738	diesel-low		Other
10	NCCWC Filter Plant	2005	2	1.8	31	122,958	61,479		8,289	29,321	diesel-low	3,066	Other
11	PCC Structurals	2005	1	0.9	11	113,874	113,874		3,639	15,167	diesel-low	3,420	Other
12	Providence Portland Medical Center	2005	6	5.4	192	265,383	44,231		46,091	43,354	diesel-low	3,857	Other
13	Salem Hospital	2006	8	7.2	135	269,108	33,639		48,702	110,556	diesel-low	2,716	Other

14	Sunrise Water Authority Pump Station	2006	1.25	1.13	14	88,272	70,618		3,308	7,132	diesel-low	2,915	Other
15	Providence Newberg Hospital	2006	1.5	1.35	24	156,833	104,555		7,255	45,134	diesel-low	3,828	Other
16	H5 (Formerly vXchnge/Sungard DSG)	2006	2	1.8	13	331,845	165,923		5,431	6,024	diesel-low	3,884	Other
17	Kaiser Sunnyside Hospital	2007	4.5	4.05	75	352,752	78,389			49,665	diesel-low	3,043	Other
18	Newberg Waste Water Treatment Plant	2008	2	1.8	31	161,586	80,793		11,218	32,908	diesel-low	3,080	Other
19	Xerox Corp	2007	4	3.6	44	384,805	96,201		14,584	71,637	diesel-low	3,094	Other
20	Newberg Water Treatment Plant	2007	1	0.9	16	85,288	85,288		7,000	11,901	diesel-low	3,103	Other
21	Oregon Dept of Admin Serv - Data Center	2010	3.86	3.47	39	332,026	86,017		24,590	44,855	diesel-low	2,647	Other
22	Amazon (Formerly Panasonic/Sanyo)	2010	1	0.9	13	43,144	43,144		3,806	38,935	diesel-low	3,140	Other
23	Sysco Foods	2010	2	1.8	24	191,908	95,954		7,366	18,025	diesel-low	3,087	Other
24	Clackamas Intertie 2	2012	0.6	0.54	8	162,961	271,602		1,728	12,411	diesel-low	2,437	Other
25	Dawson Creek	2012	0.8	0.72	4	102,835	128,544			20,434	diesel-low	3,043	Other
26	Kaiser Westside Hospital	2012	4	3.6	63	408,830	102,208		19,125	55,798	diesel-low	3,056	Other
27	North Plains Pump Station	2012	0.8	0.72	12	60,261	75,326			19,909	diesel-low	3,043	Other
28	Oak Lodge Sanitary District	2012	2	1.8	32	236,273	118,137		9,012	20,064	diesel-low	2,925	Other
29	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.5	1.25	14	284,255	189,503		7,594	11,679	diesel-low	2,633	Other
30	Oregon State Hospital	2012	4	3.6	52	172,879	43,220			79,577	diesel-low	3,043	Other
31	Portland Service Center	2012	0.5	0.45	7	329,984	659,968			10,336	diesel-low	3,043	Other
32	Sandy Highschool	2012	1.25	1.13	16	187,023	149,618		6,715	14,136	diesel-low	3,649	Other
33	TATA Communications - Hillsboro	2012	4.5	4.05	38	328,979	73,106			24,882	diesel-low	3,043	Other
34	Tri-City Wastewater Treatment Plant	2012	2.5	2.25	60	168,824	67,530		12,265	62,380	diesel-low	2,932	Other
35	TATA Communications - Portland	2013	6	5.4	61	612,983	102,164		34,757	85,771	diesel-low	2,592	Other
36	City of Hillsboro Crandall Reservoir	2013	0.8	0.72	9	112,983	141,229		4,783	6,839	diesel-low	3,099	Other
37	East County Courts	2013	1.5	1.35	17	316,848	211,232		4,509	6,404	diesel-low	3,863	Other
38	City of Portland-Columbia Blvd WWTP	2013	1	0.9	26	169,363	169,363		8,975	10,683	diesel-low	3,328	Other
39	US Foods (Formerly Food Services of America)	2013	2	1.8	36	237,459	118,730		9,926	15,174	diesel-low	6,298	Other
40	Avery DSG	2014	0.8	0.72	24	263,782	329,728			1,923	diesel-low	3,043	Other
41	Carver (Readiness Center) DSG	2014	2	1.8	52	818,635	409,318			51,608	diesel-low	3,043	Other
42	Juvenile Justice Center	2014	0.75	0.68	7	171,531	228,708			10,642	diesel-low	3,043	Other

43	Clackamas River Water	2014	2	1.8	33	390,565	195,283		8,599	8,758	diesel-low	3,857	Other
44	Joint Water Commission	2015	5	4.5	65	197,431	39,486		13,386	38,209	diesel-low	2,747	Other
45	McLane Foodservice	2016	1.5	1.35	24	190,560	127,040		7,710	16,481	diesel-low	3,746	Other
46	Flexential Brookwood (Formerly ViaWest Brookwood)	2016	16.25	14.63	768	293,759	18,077		57,713	234,264	diesel-low	2,946	Other
47	World Trade Center	2017	3.2	2.88	37	1,021,168	319,115		14,292	79,349	diesel-low	2,937	Other
48	Washington County Jail	2017	1.5	1.35	16	325,578	217,052			9,703	diesel-low	3,043	Other
49	OHSU - Vaccine Gene Therapy Institute	2017	1.5	1.25	15	366,768	244,512		4,459	19,899	diesel-low	4,210	Other
50	OHSU - Center for Health & Healing	2018	3	2.7	47	351,605	117,202		16,760	30,908	diesel-low	3,621	Other
51	OHSU - Knight Cancer Research Building	2018	2	1.8	22	237,298	118,649		6,710	12,039	diesel-low	3,576	Other
52	Hattan Road Pump Station - HRPS	2021	1	0.9		212,306	212,306			21,510	diesel-low	3,043	Other
53	Beaverton Public Service Center	2021	1	0.9	2	523,446	523,446			19,146	diesel-low	3,043	Other
54	Kellogg Creek WWTP	2022	1.5	1.35	7	276,265	184,177			15,324	diesel-low	3,043	Other
55	Solar	2012	3.02	3.02	2,778	1,324,428	438,698	483,578		39,734	solar		Solar

FERC FORM NO. 1 (REV. 12-03)

Page 410-411

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
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. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. 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.
5. 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.
6. 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).
7. 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.
8. 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.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	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			
	From (a)	To (b)	Operating (c)	Designated (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)	(i)	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
1	500KV LINES											0				0
2	(a) BOARDMAN	GRASSLAND	500	500	ST. TOWER	0.94		1	2-1780 ACSR			0				0
	(b)															

3	BROADVIEW SWITCHYARD	TOWNSEND 'A'	500	500	ST. TOWER	133.4		1				0				0
4	[c] BROADVIEW SWITCHYARD	TOWNSEND 'B'	500	500	ST. TOWER	133.4		1				0				0
5	CARTY	GRASSLAND	500	500	ST. TOWER	0.75		1	2-1780 ACSR			0				0
6	[d] COLSTRIP SWITCHYARD	BROADVIEW 'A'	500	500	ST. TOWER	112.7		1				0				0
7	[e] COLSTRIP SWITCHYARD	BROADVIEW 'B'	500	500	ST. TOWER	115.9		1				0				0
8	[f] COYOTE SPRINGS	SLATT BPA	500	500								0				0
9	GRASSLAND	SLATT BPA	500	500	ST. TOWER	16.73		1	2-1780 ACSR			0				0
10	GRIZZLY BPA	MALIN BPA #2	500	500	ST. TOWER	178.5		1	2-1780 ACSR			0				0
11	GRIZZLY BPA	ROUND BUTTE	500	500	ST. TOWER	15.6		1	2-1780 ACSR			0				0
12	[g] JOHN DAY	GRIZZLY '1'	500	500				1				0				0
13	[h] JOHN DAY	GRIZZLY '2'	500	500				1				0				0
14	TOTAL 500KV LINES									1,526,610	86,377,448	87,904,058	522,603	300,492	1,846,584	2,669,679
15	230 KV LINES											0				0
16	BEAVER	PORT WESTWARD	230	230	H-WOOD	0.41		1	2156 ACSS			0				0
17	BETHEL	McLOUGHLIN	230	230	H-WOOD	35.52		1	1272 AAC			0				0
18	BETHEL	ROUND BUTTE	230	230	H-WOOD/ST. TOWER	98.68		1	1272 AAC/1272 ACSR			0				0
19	BETHEL	SANTIAM BPA	230	230	H-WOOD	3.64		1	795 ACSR			0				0
20	[i] BIG EDDY BPA	McLOUGHLIN	230	230	H-WOOD	0.91		1	1780 ACSR			0				0
21	[j] BIGLOW CANYON WF	JOHN DAY #1 BPA	230	230				1	2388 AAC TW			0				0
22	BLUE LAKE	GRESHAM	230	230	ST. TOWER	5.92		2	1272 ACSS			0				0
23	BLUE LAKE	TROUTDALE BPA #1	230	230	ST. MONOP/ST. TOWER	1.45		1	1272 ACSS			0				0
24	BLUE LAKE	TROUTDALE BPA #2	230	230	ST. MONOP/ST. TOWER	0.15	1.34	2	1272 ACSS			0				0
25	[k] CARLTON BPA	SHERWOOD	230	230	ST. TOWER	8.95		2	1272 AAC			0				0
26	CARVER	GRESHAM #1	230	230	H-WOOD	7.33		1	1272 AAC			0				0
27	CARVER	McLOUGHLIN #1	230	230	H-WOOD/ST. MONOP	4.87		1	1272 AAC			0				0
28	CARVER	McLOUGHLIN #2	230	230	ST. MONOP		4.88	1	1272 ACSS			0				0
29	CENTRAL FERRY BPA	MULLAN (TUCANNON WF)	230	230	H-WOOD	20.62		1	954 ACSR			0				0
30	DALREED PACW	[q] CARTY	230	230	H-WOOD	16.76		1	795 AAC			0				0
	[l]															

31	GRESHAM	TROUTDALE PACW #1	230	230	H-WOOD	0.43		1	954 ACSR			0				0
32	GRESHAM	TROUTDALE PACW #2	230	230	ST. TOWER	0.33		1	1272 AAC			0				0
33	HARBORTON	RIVERGATE #1	230	230	ST. TOWER/H-WOOD	1.7		1	1272 AAC			0				0
34	HARBORTON	TROJAN #1	230	230	ST TOWER	33.6		2	1590 AAC			0				0
35	HORIZON	KEELER BPA	230	230	ST. MONOP	1.47		2	1272 ACSS			0				0
36	HORIZON	ST. MARYS - TROJAN	230	230	ST. TOWER/ST. MONOP	12.95	32.95	1	1590 AAC			0				0
37	[m] KEELER BPA	RIVERGATE	230	230	ST. TOWER	0.08		2	1272 AAC			0				0
38	KEELER BPA	ST. MARYS	230	230	H-WOOD/ST. TOWER	6.47		2	1590 ACSR TWD			0				0
39	McLOUGHLIN	PEARL BPA - SHERWOOD	230	230	ST. TOWER/ST. MONOP	16.38	4.7	2	2-1272 AAC/1272 AAC/2-1780 ACSR			0				0
40	MURRAYHILL	SHERWOOD #1	230	230	ST. TOWER	5.58		2	1272 AAC			0				0
41	MURRAYHILL	SHERWOOD #2	230	230	ST. TOWER		5.55	2	1272 AAC			0				0
42	MURRAYHILL	ST. MARYS	230	230	ST. TOWER	5.2		2	1272 ACSS			0				0
43	[n] PEARL BPA	SHERWOOD	230	230	ST. MONOP/ST. TOWER/H-WOOD	4.88		1	2-2388 AAC TW			0				0
44	[o] PELTON	ROUND BUTTE	230	230	H-WOOD	7.87		1	795 ACSR			0				0
45	PORT WESTWARD	TROJAN #1	230	230	H-WOOD/ST. MONOP	18.76		1	2156 ACSS			0				0
46	PORT WESTWARD	TROJAN #2	230	230	H-WOOD/ST. MONOP	9.28	9.48	2	2156 ACSS			0				0
47	REDMOND BPA	ROUND BUTTE	230	230	H-WOOD	23.81		1	795 ACSR			0				0
48	[p] RIVERGATE	ROSS BPA	230	230	ST. TOWER	0.09		2	795 ACSR			0				0
49	ROUND BUTTE	GENERATOR #1	230	230	ST. TOWER			1	795 ACSR			0				0
50	ROUND BUTTE	GENERATOR #2	230	230	ST. TOWER			1	795 ACSR			0				0
51	ROUND BUTTE	GENERATOR #3	230	230	ST. TOWER			1	795 ACSR			0				0
52	TOTAL 230KV LINES									8,602,221	138,275,827	146,878,048	387,109	227,952	85,712	700,773
53	ALL 115KV LINES					438.81						0				0
54	ALL 57KV LINES					11.81						0				0
55	TOTAL 115KV & 57KV LINES									1,038,185	221,490,513	222,528,698	2,935,613	3,246,909		6,182,522
36	TOTAL					1,512.63	58.9	60		11,167,016	446,143,788	457,310,804	3,845,325	3,775,353	1,932,296	9,552,974

FERC FORM NO. 1 (ED. 12-87)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionLineStartPoint	
Jointly owned with Idaho Power Company. Total length is indicated. Costs are respondent's share.	
(b) Concept: TransmissionLineStartPoint	
Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.	
(c) Concept: TransmissionLineStartPoint	
Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.	
(d) Concept: TransmissionLineStartPoint	
Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.	
(e) Concept: TransmissionLineStartPoint	
Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. Total length is indicated. Costs are respondent's share.	
(f) Concept: TransmissionLineStartPoint	
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.	
(g) Concept: TransmissionLineStartPoint	
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.	
(h) Concept: TransmissionLineStartPoint	
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.	
(i) Concept: TransmissionLineStartPoint	
Represents ownership of one circuit on Bonneville Power Administration's double circuit line.	
(j) Concept: TransmissionLineStartPoint	
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.	
(k) Concept: TransmissionLineStartPoint	
Represents ownership of one circuit on Bonneville Power Administration's double circuit line.	
(l) Concept: TransmissionLineStartPoint	
Represents contract with PacifiCorp whereby PGE is entitled to 1/2 the capacity of the line.	
(m) Concept: TransmissionLineStartPoint	
Represents partial ownership of one circuit on Bonneville Power Administration's line.	
(n) Concept: TransmissionLineStartPoint	
Represents ownership of one circuit on Bonneville Power Administration's double circuit line.	
(o) Concept: TransmissionLineStartPoint	
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon.Total length is indicated. Costs are respondent's share.	
(p) Concept: TransmissionLineStartPoint	
Represents partial ownership of one circuit on Bonneville Power Administration's line.	
(q) Concept: TransmissionLineEndPoint	
Jointly owned with Idaho Power Company. Total length is indicated. Costs are respondent's share.	

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)

1	Brookwood	Shute	2.88	ST. MONOP	21	1	1	795 ACSS			115	204,774	7,104,465	4,736,310		12,045,549	
2	Brookwood	St Marys	5.98	ST. MONOP	22	1	1	795 ACSS			115	60,247	13,352,159	8,901,439		22,313,845	
3	Curtis	Northern	2.7	H-WOOD	27	1	1	795 AAC			115		455,920	195,394		651,314	
4	Northern	Rivergate	3.41	H-WOOD	26	1	1	795 AAC			115		227,960	97,697		325,657	
44	TOTAL		14.97		96	4	4					265,021	21,140,504	13,930,840	0	35,336,365	

FERC FORM NO. 1 (REV. 12-03)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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).
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.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1	2 Substation Under 10 MVA capacity	Distribution	Unattended	115	13	0	16.8	2		Capacitor Banks	2	3.6
2	6 Substation Under 10 MVA capacity	Distribution	Unattended	57	13	0	44.3	8				
3	Abernethy, Oregon City, OR	Distribution	Unattended	115	13	0	44.8	2		Capacitor Banks	4	12
4	Alder, Portland, OR	[ad] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	4	12
5	Amity, near Amity, OR	Distribution	Unattended	57	13	0	7.5	1				
6	Arleta, Portland, OR	Distribution	Unattended	57	13	0	47.6	2		Capacitor Banks	2	7.2
7	[a] Bakeoven, BPA, Near Bakeoven, OR	Transmission	Unattended	500								
8	Banks, Banks, OR	Distribution	Unattended	57	13	0	20	1		Capacitor Banks	2	3
9	Barnes, Salem, OR	Distribution	Unattended	115	13	0	42.4	2		Capacitor Banks	2	6
10	Beaver Plant, near Clatskanie, OR	Transmission	Unattended	230	13	0	464	4				
11	Beaver Plant, near Clatskanie, OR	Transmission	Unattended	230	24	0	170	1				
12	Beaverton, Beaverton, OR	[ae] Transmission	Unattended	115	13	0	33.6	2		Capacitor Banks	4	12
13	Bell, near Portland, OR	[af] Transmission	Unattended	115	13	0	65.8	3		Capacitor Banks	6	18
14	Bethany, Portland, OR	[ag] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	5	15
15	Bethel, Salem, OR	[ah] Transmission	Unattended	230	115	13	642	3				

16	Bethel, Salem, OR	[(ai)] Transmission	Unattended	115	13	0	28	1		Capacitor Banks	2	6
17	Biglow Canyon Windfarm	Transmission	Unattended	230	34.5	13	480	3				
18	Blue Lake, Troutdale, OR	[(aj)] Transmission	Unattended	230	115	13	640	2				
19	Blue Lake, Troutdale, OR	[(ak)] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	4	12
20	Boones Ferry, Lake Oswego, OR	[(al)] Transmission	Unattended	115	13	0	50	2		Capacitor Banks	2	7.2
21	Boring, near Boring, OR	Distribution	Unattended	57	13	0	16.8	1		Capacitor Banks	1	12.15
22	[(b)] Broadview Subst. near Broadview, MT	Transmission	Unattended	500	230	0	80	3				
23	Brookwood, near Hillsboro, OR	Transmission	Unattended	115	13	0	100	2		Capacitor Banks	4	12
24	[(c)] Buckley, BPA near Buckley, WA	Transmission	Unattended	500								
25	Butler, Hillsboro OR	[(am)] Transmission	Unattended	115	13	0	300	2		Capacitor Banks	2	48
26	Canby, near Barlow, OR	Distribution	Unattended	57	13	0	39.3	4				
27	Canemah, Oregon City, OR	[(an)] Transmission	Unattended	115	57	13	264.8	4	2			
28	Canyon, Portland, OR	[(ao)] Transmission	Unattended	115	13	0	200	4		Capacitor Banks	8	28.8
29	[(d)] Captain Jack, BPA, Near Malin, OR	Transmission	Unattended	500								
30	Carty, near Boardman, OR	Transmission	Unattended	500	230	24	1170.5	4				
31	Carty, near Boardman, OR	Transmission	Unattended	230	7.2	0	55	1				
32	Carver, Carver, OR	[(ap)] Transmission	Unattended	230	115	13	640	2				
33	Carver, Carver, OR	[(aq)] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	4	12
34	Cascade, St Helens, OR	Distribution	Unattended	115	13	0	46.4	2	1	Capacitor Banks	4	12
35	Cedar Hills, near Beaverton, OR	Distribution	Unattended	115	13	0	56	2		Capacitor Banks	4	13.2
36	Centennial, near Gresham, OR	Distribution	Unattended	115	13	0	39.2	2		Capacitor Banks	2	7.2
37	[(e)] Chemawa BPA, near Salem, OR	Distribution	Unattended	115	0	0	0					
38	[(f)] Chemawa BPA, near Salem, OR	Distribution	Unattended	57	0	0	0					
39	Clackamas, Clackamas, OR	[(ar)] Transmission	Unattended	115	13	0	43	2		Capacitor Banks	4	13.2
40	Claxtar, Salem,OR	Distribution	Unattended	57	13	0	28	1		Capacitor Banks	2	6
41	Coffee Creek, Sherwood, OR	Distribution	Unattended	115	13	0	28	1		Capacitor Banks	2	6
42	[(g)] Colstrip Plant, near Colstrip, MT	Transmission	Unattended	500	26	0	164	3				
43	[(h)] Colstrip Subst. near Colstrip, MT	Transmission	Unattended	500	230	0	100	2				
44	Cornelius, Cornelius, OR	[(as)] Transmission	Unattended	57	13	0	28	1		Capacitor Banks	2	6
45	Cornelius, Cornelius, OR	[(at)] Transmission	Unattended	115	57	13	140	1	1			
46	Cornell, Portland, OR	Distribution	Unattended	115	13	0	28	1		Capacitor Banks	2	6

47	[i] Coyote Springs, Boardman, OR	Transmission	Unattended	500			300	3				
48	Culver, Salem, OR	[au] Transmission	Unattended	115	13	0	28	1				
49	Curtis, Portland, OR	[av] Transmission	Unattended	115	13	0	16.8	1		Capacitor Banks	2	6
50	Dayton, near Dayton , OR	[aw] Transmission	Unattended	57	13	0	19.5	2		Capacitor Banks	4	6
51	Dayton, near Dayton , OR	[ax] Transmission	Unattended	115	57	13	125	1				
52	Delaware, Portland, OR	[ay] Transmission	Unattended	115	13	0	28	1				
53	Denny, Beaverton, OR	[az] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	2	6
54	Dilley, near Forest Grove, OR	Distribution	Unattended	57	13	0	12.5	1		Capacitor Banks	3	9
55	Dunns Corner, near Sandy,OR	[ba] Transmission	Unattended	57	13	0	14	1		Capacitor Banks	2	3
56	Durham, Tigard , OR	Distribution	Unattended	115	13	0	77	4		Capacitor Banks	4	12.6
57	E., Portland, OR	[bb] Transmission	Unattended	115	13	0	202.4	5		Capacitor Banks	4	28.8
58	E., Portland, OR	[bc] Transmission	Unattended	115	11	0	132.4	4		Capacitor Banks	1	24
59	Eagle Creek, Eagle Creek, OR	Distribution	Unattended	57	13	0	14	1				
60	Eastport, Portland, OR	[bd] Transmission	Unattended	115	13	0	16.8	1		Capacitor Banks	2	6
61	Elma, near Salem, OR	Distribution	Unattended	57	13	0	56	2		Capacitor Banks	4	12
62	Estacada, Estacada, OR	Distribution	Unattended	57	13	0	29.6	2		Capacitor Banks	2	3.6
63	Fairmount, Salem, OR	[be] Transmission	Unattended	115	13	0	25	1		Capacitor Banks	1	3.6
64	Fairview, Fairview, OR	[bf] Transmission	Unattended	115	13	0	50.4	2		Capacitor Banks	1	3
65	Faraday Plant, near Estacada, OR	[bg] Transmission	Unattended	115	13	0	27	1				
66	Faraday, Switchyard, OR	[bh] Transmission	Unattended	115	57	13	140	1				
67	Faraday, Switchyard, OR	[bi] Transmission	Unattended	57	11	0	32	2				
68	[j] Forest Grove BPA, Forest Grove, OR	Transmission	Unattended	115	0	0	0					
69	[k] Fort Rock, 12 mi NE of Silver Lake, OR	Transmission	Unattended	500	0	0	0			Series Capacitor	1	363
70	Garden Home, near Portland, OR	Distribution	Unattended	115	13	0	28	1				
71	Glencoe, Portland, OR	Distribution	Unattended	115	13	0	25	1		Capacitor Banks	2	6
72	Glencullen, Portland, OR	[bj] Transmission	Unattended	115	13	0	24	1		Capacitor Banks	2	6
73	Glendoveer, near Portland, OR	[bk] Transmission	Unattended	115	13	0	50.4	2				
74	Glisan, Gresham, OR	[bl] Transmission	Unattended	115	13	0	44.8	2		Capacitor Banks	4	12
75	Grand Ronde, Grand Ronde, OR	[bm] Transmission	Unattended	115	57	13	33	1	1			
76	Grand Ronde, Grand Ronde, OR	[bn] Transmission	Unattended	115	13	0	12.5	1		Capacitor Banks	2	3
77	Grassland, near Boardman, OR	Transmission	Unattended	500	0	0	0					

78	Gresham, near Gresham, OR	Transmission	Unattended	230	115	13	572	2				
79	[l] Grizzly, BPA, near Madras, OR	Transmission	Unattended	500	0	0	0					
80	Harborton, near Portland, OR	[bo] Transmission	Unattended	230	115	13	320	1		Capacitor Banks	1	24
81	Harborton, near Portland, OR	[bp] Transmission	Unattended	115	13	0	53	2		Capacitor Banks	4	12
82	Harmony, near Milwaukie, OR	Distribution	Unattended	115	13	0	50.4	2		Capacitor Banks	4	12
83	Harrison Sub, Portland, OR	[bq] Transmission	Unattended	115	13	0	28	1		Capacitor Banks	2	6
84	Hayden Island, near Portland, OR	Distribution	Unattended	115	13	0	33.6	2		Capacitor Banks	4	12
85	Helvetia, Hillsboro, OR	[br] Transmission	Unattended	115	34.5	0	100	2		Capacitor Banks	4	18
86	Hemlock, Portland, Or	Distribution	Unattended	115	13	0	28	1		Capacitor Banks	2	6
87	Hillcrest, Salem , OR	[bs] Transmission	Unattended	115	13	0	28	1		Capacitor Banks	2	6
88	Hillsboro, Hillsboro , OR	Distribution	Unattended	57	13	0	43.4	2		Capacitor Banks	4	14.4
89	Hogan North, Gresham, OR	Distribution	Unattended	115	13	0	56	2		Capacitor Banks	4	12
90	Hogan South, Gresham, OR	[bt] Transmission	Unattended	115	57	13	125	3				
91	Hogan South, Gresham, OR	[bu] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	4	12
92	Holgate, Portland, OR	Distribution	Unattended	57	13	0	39.2	2		Capacitor Banks	2	7.2
93	Horizon, Hillsboro, OR	Transmission	Unattended	230	115	13	960	3				
94	Huber, near Beaverton, OR	Distribution	Unattended	115	13	0	56	2		Capacitor Banks	2	6
95	Indian, near Salem, OR	[bv] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	3	10.8
96	Island, near Milwaukie, OR	[bw] Transmission	Unattended	115	13	0	44.8	2		Capacitor Banks	4	12
97	Jennings Lodge, Jennings Lodge, OR	Distribution	Unattended	115	13	0	52.5	2				
98	[m] Keeler, BPA, Hillsboro, OR	Transmission	Unattended	0								
99	Kelley Point, Portland, OR	Distribution	Unattended	115	13	0	56	2		Capacitor Banks	4	12
100	Kelly Butte, Portland, OR	[bx] Transmission	Unattended	115	13	0	44.8	2		Capacitor Banks	2	6
101	King City, near King City, OR	[by] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	4	12
102	Leland, Oregon City, OR	Distribution	Unattended	57	13	0	28	1		Capacitor Banks	2	6
103	Lents, near Portland, OR	Distribution	Unattended	115	13	0	22.4	1				
104	Lents, near Portland, OR	Distribution	Unattended	57	11	0	20	2				
105	Liberal	Distribution	Unattended	115	13	0	14	1		Capacitor Banks	1	12
106	Liberty, Salem, OR	[bz] Transmission	Unattended	115	13	0	50.4	2		Capacitor Banks	3	10.2
107	Main, Hillsboro, OR	Distribution	Unattended	57	13	0	84	3		Capacitor Banks	6	20.4
108	[n] Malin, BPA, near Malin, OR	Transmission	Unattended	500	0	0	0			Reactors	3	180
109	Market, Salem, OR	[ca] Transmission	Unattended	115	13	0	28	1		Capacitor Banks	2	6
110	Marquam, Portland OR	[cb] Transmission	Unattended	115	13	0	250	5		Capacitor Banks	10	54
111	McClain, Salem, OR	Distribution	Unattended	57	13	0	22.5	3				
112	McGill, Gresham, OR	[cc] Transmission	Unattended	115	13	0	75.4	3		Capacitor Banks	6	18

113	McLoughlin, near Oregon City, OR	[cd] Transmission	Unattended	230	115	13	640	2				
114	Meridian, near Tualatin, OR	[ce] Transmission	Unattended	115	13	0	84	3		Capacitor Banks	6	18
115	Middle Grove, near Middle Grove, OR	Distribution	Unattended	115	13	0	56	2		Capacitor Banks	4	12
116	Midway, near Portland, OR	Distribution	Unattended	115	13	0	33.6	2		Capacitor Banks	1	3.6
117	Mill Creek, near Salem, OR	[cf] Transmission	Unattended	115	13	0	16.8	1		Capacitor Banks	2	6
118	Mobile No. 1, OR	Distribution	Unattended	115	57	13	25	1				
119	Mobile No. 2, OR	Distribution	Unattended	115	57	13	34	1				
120	Mobile No. 3, OR	Distribution	Unattended	115	57	13	29	1				
121	Mobile No. 4 OR	Distribution	Unattended	115	57	13	34	1				
122	Mobile No. 5 OR	Distribution	Unattended	115	57	13	34	1				
123	Mobile No. 6 OR	Distribution	Unattended	115	57	13	34	1				
124	Mobile No. 7 OR	Distribution	Unattended	115	57	13	25	1				
125	Mobile No. 8 OR	Distribution	Unattended	115	57	13	25	1				
126	Molalla, Molalla, OR	Distribution	Unattended	57	13	0	42.4	2		Capacitor Banks	4	9
127	Monitor, near Monitor, OR	[cg] Transmission	Unattended	230	57	13	125	1				
128	Mt. Angel, Mt. Angel, OR	Distribution	Unattended	57	13	0	20	1		Capacitor Banks	3	15
129	Mt. Pleasant, Oregon City , OR	Distribution	Unattended	115	13	0	44.8	2		Capacitor Banks		
130	Multnomah, Portland, OR	Distribution	Unattended	115	13	0	39.2	2		Capacitor Banks	3	9
131	Murrayhill, Beaverton, OR	[ch] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	3	10.8
132	Murrayhill, Beaverton, OR	[ci] Transmission	Unattended	230	115	13	320	1				
133	Newberg, Newberg, OR	[cj] Transmission	Unattended	115	13	0	44.8	2		Capacitor Banks	4	12
134	North Fork, near Estacada, OR	Transmission	Unattended	115	13	0.48	53	3				
135	North Marion, near Woodburn, OR	Distribution	Unattended	57	13	0	30.88	3		Capacitor Banks	3	15
136	North Plains, North Plains, OR	Distribution	Unattended	57	13	0	20	1		Capacitor Banks	4	16.5
137	Northern, Portland, OR	Transmission	Unattended	115	13	0	28	1				
138	Oak Grove, Three Lynx, OR	[ck] Transmission	Unattended	115	13	0	8	1				
139	Oak Grove, Three Lynx, OR	[cl] Transmission	Unattended	115	11	0	64	2				
140	Oak Grove, Three Lynx, OR	[cm] Transmission	Unattended	13	11	0	0					
141	Oak Grove, Three Lynx, OR	[cn] Transmission	Unattended	13	0.48	0	0					
142	Oak Hills, near Beaverton, OR	Distribution	Unattended	115	13	0	44.8	2		Capacitor Banks	4	14.4
143	[o] Oregon City - BPA, Wilsonville, OR	Distribution	Unattended	57	0	0	0					
144	Orenco, near Hillsboro, OR	[co] Transmission	Unattended	115	57	13	280	2				
145	Orenco, near Hillsboro, OR	[cp] Transmission	Unattended	115	13	0	81.2	3		Capacitor Banks	6	18
146	Orient, near Gresham, OR	Distribution	Unattended	57	13	0	28	1		Capacitor Banks	2	6
147	Oswego, Lake Oswego, OR	[cq]	Unattended	115	13	0	33.6	2		Capacitor Banks	2	7.2

		Transmission										
148	Oxford, Salem, OR	(cr) Transmission	Unattended	115	13	0	50.4	2		Capacitor Banks	4	12.3
149	(p) Pearl, BPA, near Wilsonville, OR	Transmission	Unattended	230	0	0	0					
150	(q) Pelton, near Madras , OR	Transmission	Unattended	230	13	0	120	3				
151	(r) Pelton, near Madras, OR	Transmission	Unattended	13	13	0	3	1				
152	Peninsula Park, Portland, OR	Distribution	Unattended	115	13	0	28	1		Capacitor Banks	2	6
153	Pleasant Valley, near Portland, OR	(cs) Transmission	Unattended	115	13	0	56	2		Capacitor Banks	4	12
154	Port Westward, near Clatskanie, OR	Transmission	Unattended	230	18	0	900	3				
155	Port Westward, near Clatskanie, OR	Transmission	Unattended	13	4.2	0	40	2				
156	Portsmouth, Portland, OR	(ct) Transmission	Unattended	115	13	0	28	1				
157	Progress, near Tigard, OR	(cu) Transmission	Unattended	115	13	0	50	2		Capacitor Banks	4	13.8
158	Raleigh Hills, near Portland, OR	Distribution	Unattended	115	13	0	28	1		Capacitor Banks	2	6.6
159	Ramapo, near Portland, OR	Distribution	Unattended	115	13	0	28	1		Capacitor Banks	2	6
160	Redland, near Oregon City, OR	Distribution	Unattended	115	13	0	22.4	1				
161	Reedville, near Beaverton, OR	(cv) Transmission	Unattended	115	13	0	84	3		Capacitor Banks	6	20.4
162	(s) Rhododendron Switching, OR	Distribution	Unattended	57	0	0	0					
163	River Mill, near Estacada, OR	(cw) Transmission	Unattended	57	11	0	32	2				
164	Rivergate North Yard, Portland, OR	(cx) Transmission	Unattended	230	115	13	520	4	1	Capacitor Banks	1	24
165	Rivergate South Yard, Portland, OR	(cy) Transmission	Unattended	115	13	0	22.4	1		Capacitor Banks	2	7.2
166	Rivergate South Yard, Portland, OR	(cz) Transmission	Unattended	115	11	0	22.4	1		Capacitor Banks	2	6.716
167	Riverview, Portland, OR	Distribution	Unattended	115	13	0	28	1		Capacitor Banks	2	6
168	Rock Creek, near Portland, OR	(da) Transmission	Unattended	115	113	0	28	1		Capacitor Banks	2	6
169	Rockwood, near Gresham, OR	Distribution	Unattended	115	13	0	78.4	3		Capacitor Banks	5	15
170	Rosemont, near Lake Oswego, OR	(db) Transmission	Unattended	115	13	0	28	1		Capacitor Banks	2	6
171	Roseway, Hillsboro, OR	Distribution	Unattended	115	13	0	56	2		Capacitor Banks	4	12
172	(t) Round Butte, near Madras, OR	(dc) Transmission	Unattended	500	230	12	561	3		Reactors	12	180
173	(u) Round Butte, near Madras, OR	(dd) Transmission	Unattended	230	13	0	394	4				
174	Ruby, Gresham, OR	(de) Transmission	Unattended	115	13	0	28	1		Capacitor Banks	2	6
175	Salem-PGE, near Salem, OR	Distribution	Unattended	57	13	0	44.8	2		Capacitor Banks	4	12
176	(v) Sand Springs, South of Bend, OR	Transmission	Unattended	500	0	0	0			Series Capacitor	1	546
177	Sandy, Sandy, OR	Distribution	Unattended	57	13	0	28	1		Capacitor Banks	2	6

178	[w] Scappoose, Scappoose, OR	[df] Transmission	Unattended	115	0	0	0					
179	Scholls Ferry, Beaverton, OR	[dg] Transmission	Unattended	115	13	0	28	1		Capacitor Banks	2	6
180	Scoggins, near Gaston, OR	Distribution	Unattended	57	13	0	13	2		Capacitor Banks	1	10.8
181	Sellwood, Portland, OR	[dh] Transmission	Unattended	115	57	13	140	1		Capacitor Banks	1	24
182	Sellwood, Portland, OR	[di] Transmission	Unattended	115	13	0	28	1		Capacitor Banks	2	6
183	Sheridan, Sheridan, OR	Distribution	Unattended	57	13	0	16.8	1		Capacitor Banks	3	15.6
184	Sherwood, near Six Corners, OR	Transmission	Unattended	230	115	13	640	2				
185	Shute, Hillsboro, OR	[dj] Transmission	Unattended	115	34.5	0	400	4		Capacitor Banks	8	36
186	Silverton, Silverton, OR	Distribution	Unattended	57	13	0	42	2				
187	Six Corners, Six Corners, OR	[dk] Transmission	Unattended	115	13	0	49	2		Capacitor Banks	4	12
188	[x] Slatt, BPA, Arlington, OR	Transmission	Unattended	500								
189	Springbrook, Newberg, OR	[dl] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	5	36
190	[y] St. Helens, near St. Helens, OR	[dm] Transmission	Unattended	115	0	0	0			Capacitor Banks	1	24
191	St. Louis, Gervais, OR	Distribution	Unattended	57	13	0	23.5	2		Capacitor Banks	2	7.2
192	St. Marys, East Yard, Beaverton, OR	[dn] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	4	12
193	St. Marys, West Yard, Beaverton, OR	[do] Transmission	Unattended	230	115	13	960	3		Capacitor Banks	3	108
194	Sullivan, West Linn, OR	[dp] Transmission	Unattended	57	4.15	0	33	1				
195	Sullivan, West Linn, OR	[dq] Transmission	Unattended	115	13	0	44.8	2		Capacitor Banks	4	12
196	Summit, Government Camp, OR	Distribution	Unattended	57	13	0	8.4	1				
197	Summit, Government Camp, OR	Distribution	Unattended	24	13	0	14	1				
198	Sunset, near Hillsboro, OR	[dr] Transmission	Unattended	115	13	0	400	8		Capacitor Banks	8	43.2
199	Sunset, near Hillsboro, OR	[ds] Transmission	Unattended	115	34.5	0	375	3		Capacitor Banks	5	45.6
200	Swan Island, Portland, OR	Distribution	Unattended	115	13	0	56	2		Capacitor Banks	4	12
201	[z] Sycan, 27 mi S of Silver Lake, OR	Transmission	Unattended	500	0	0	0			Series Capacitor	1	546
202	Sylvan, near Portland, OR	Distribution	Unattended	115	13	0	22.4	1		Capacitor Banks	2	4.8
203	[aa] Tabor, Portland, OR	[dt] Transmission	Unattended	57	0	0	0					
204	Tabor, Portland, OR	[du] Transmission	Unattended	115	13	0	22.4	1		Capacitor Banks	2	6
205	Tektronix, Beaverton, OR	[dv] Transmission	Unattended	115	13	0	84	3		Capacitor Banks	6	18
206	Temp A, OR	Distribution	Unattended	115	57	13	20	1				
207	Temp C, OR	Distribution	Unattended	115	57	13	28	1				
208	Temp G, OR	Distribution	Unattended	115	57	13	28	1				
209	Temp H, OR	Distribution	Unattended	115	11	0	21	1				
210	Tigard, Tigard, OR	Distribution	Unattended	115	13	0	44.8	2		Capacitor Banks	4	12

211	Town Center, Portland, OR	[dw] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	2	6
212	Trojan, near Rainier, OR	[dx] Transmission	Unattended	230	13	0	56	2				
213	[ab] Troutdale, BPA near Troutdale OR	Transmission	Unattended	230								
214	Tualatin, Tualatin, OR	[dy] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	4	14.4
215	Tucannon Mullan Switchyard, Tucannon Dayton, Wa	Transmission	Unattended	230	34.5	13	320	2		Capacitors/reactors	6	90
216	Twilight, Canby, OR	Distribution	Unattended	57	13	0	28	1	1	Capacitor Banks	3	19.2
217	University, Salem, OR	[dz] Transmission	Unattended	115	13	0	22.4	1		Capacitor Banks	2	7.2
218	Urban, Portland, OR	[ea] Transmission	Unattended	115	13	0	106.4	4		Capacitor Banks	5	39.6
219	Wacker, Portland, OR	[eb] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	2	6
220	Waconda, near Hopmere, OR	Distribution	Unattended	57	13	0	40.6	2		Capacitor Banks	2	6
221	Wallace, Salem, OR	Distribution	Unattended	57	13	0	28	1		Capacitor Banks	2	6
222	Welches, near Welches, OR	Distribution	Unattended	57	24	0	10	1	1	Capacitor Banks	1	12
223	Welches, near Welches, OR	Distribution	Unattended	57	13	0	18	2		Capacitor Banks	2	6
224	[ac] West Portland, Lower Yard, Tigard, OR	[ec] Transmission	Unattended	115	0	0	0			Capacitor Banks	1	24
225	West Portland, Upper Yard, Tigard, OR	[ed] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	4	14.4
226	West Union, near Hillsboro, OR	[ee] Transmission	Unattended	115	13	0	56	2		Capacitor Banks	4	12
227	Willamina, near Willamina, OR	Distribution	Unattended	57	13	0	30.8	2		Capacitor Banks	3	7.8
228	Willbridge, Portland, OR	Distribution	Unattended	115	11	0	28	1				
229	Wilsonville, near Wilsonville, OR	[ef] Transmission	Unattended	115	13	0	84	3		Capacitor Banks	6	18
230	Woodburn, Woodburn, OR	Distribution	Unattended	57	13	0	42	2		Capacitor Banks	4	13.2
231	Yamhill, near Yamhill, OR	Distribution	Unattended	57	13	0	15.3	2		Capacitor Banks	1	1.8
232	Distribution Substations			7,939	1,607	143	2,873.08	143	3		164	562.05
233	Distribution Substations Unattended			7,939	1,607	143	2,873.08	143	3		164	562.05
234	Transmission Substations			24,091	4,160.53	322.48	19,294.7	253	5		290	3,138.4159999999993
235	Transmission Substations Unattended			24,091	4,160.53	322.48	19,294.7	253	5		290	3,138.4159999999993
236	Total						22,167.78					

FERC FORM NO. 1 (ED. 12-96)

Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: SubstationNameAndLocation

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

(b) Concept: SubstationNameAndLocation

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.

(c) Concept: SubstationNameAndLocation

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.
(d) Concept: SubstationNameAndLocation
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.
(e) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(f) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(g) Concept: SubstationNameAndLocation
Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 20% share of the jointly owned capacity. 100% of the capacity is reported.
(h) Concept: SubstationNameAndLocation
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.
(i) Concept: SubstationNameAndLocation
Contribution in aid of construction made to Bonneville Power Administration in 1995 and 2006 to FERC account 353.
(j) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(k) Concept: SubstationNameAndLocation
Line compensation only.
(l) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(m) Concept: SubstationNameAndLocation
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.
(n) Concept: SubstationNameAndLocation
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.
(o) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(p) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(q) Concept: SubstationNameAndLocation
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 64.01% share of the jointly owned capacity. 100% of the capacity is reported.
(r) Concept: SubstationNameAndLocation
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 64.01% share of the jointly owned capacity. 100% of the capacity is reported.
(s) Concept: SubstationNameAndLocation
Switching only.
(t) Concept: SubstationNameAndLocation
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 64.01% share of the jointly owned capacity. 100% of the capacity is reported.
(u) Concept: SubstationNameAndLocation
Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 64.01% share of the jointly owned capacity. 100% of the capacity is reported.
(v) Concept: SubstationNameAndLocation
Line compensation only.
(w) Concept: SubstationNameAndLocation
Switching only. Distribution owned by Columbia River PUD.
(x) Concept: SubstationNameAndLocation
Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 353.
(y) Concept: SubstationNameAndLocation
Switching only. Distribution owned by Columbia River PUD.
(z) Concept: SubstationNameAndLocation
Line compensation only.
(aa) Concept: SubstationNameAndLocation
Switching only.
(ab) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(ac) Concept: SubstationNameAndLocation
Switching only.
(ad) Concept: SubstationCharacterDescription
The substation has a mix of both transmission and distribution assets.

(ae) Concept: SubstationCharacterDescription
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Name of Respondent: Portland General Electric Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 04/14/2023	Year/Period of Report End of: 2022/ 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 Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Lease Payments for Corporate Headquarters at WTC	121 SW Salmon Street Corp	418	7,146,509
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Administrative Services	121 SW Salmon Street Corp	146	2,220,185
42				