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)	Year/Period of Report
Portland General Electric Company	End of: 2024/ Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

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.

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:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

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.

The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

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

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:

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

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

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.

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.

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.

When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

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

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.

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.

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.

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.

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).

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.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

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.

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

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.

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:

'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;

'Person' means an individual or a corporation;

'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;

'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; ......

"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

'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.

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).

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
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: 2024/ 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 Ryan Van Oostrum	06 Title of Contact Person Controller
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) 464-8426	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/11/2025

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 Joseph R. Trpik	03 Signature Joseph R. Trpik	04 Date Signed (Mo, Da, Yr) 04/11/2025
02 Title Senior Vice President, Finance and Chief Financial 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.

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".

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
57	**Amounts included in ISO/RTO Settlement Statements**	397	
58	**Purchase and Sale of Ancillary Services**	398	
59	**Monthly Transmission System Peak Load**	400	
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	not applicable
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	
64	**Hydroelectric Generating Plant Statistics**	406	
65	**Pumped Storage Generating Plant Statistics**	408	none
66	**Generating Plant Statistics Pages**	410	
66.1	**Energy Storage Operations (Large Plants)**	414	
66.2	**Energy Storage Operations (Small Plants)**	419	
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☐ No annual report to stockholders is prepared		

GENERAL INFORMATION

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

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Ryan Van Oostrum

Controller

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.

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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 through the purchase and sale of electricity, natural gas, and environmental credits in an effort to obtain reasonably-priced power to serve its retail customers, manage risk, and administer its long-term wholesale contracts.

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: 04/11/2025	Year/Period of Report End of: 2024/ Q4

CONTROL OVER RESPONDENT

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

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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 owns 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 provides property management for the Respondent and holds the World Trade Center Franchise	100	
3	Salmon Springs Hospitality Group, Inc.	Company hosts Corporate and social gatherings and events.	100	
4	121 SW Salmon Street LLC	Established to own, lease and manage the World Trade Center in Portland Oregon		
5	Portland Renewable Resource Company LLC	Established to conduct any lawful purpose		

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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]1,157,916		
2	Vice President Strategy Regulation and Energy Supply	Brett Sims	318,158		2024-10-01
3	Senior Vice President, Advanced Energy Delivery	Larry N. Bekkedahl	491,152		
4	Vice President, Digital Solutions and Chief Information Officer	John Kochavatr	513,808		
5	Vice President, Human Resources, Diversity, Equity and Inclusion	Anne E. Mersereau	427,335		
6	Senior Vice President, Chief Legal and Compliance Officer	Angelica Espinosa	541,082		
7	Executive Vice President, Chief Operating Officer	Benjamin Felton	678,862		
8	Senior Vice President and Chief Financial Officer	Joseph Trpik	632,471		
9	Vice President Chief Commercial and Customer Officer	John McFarland	250,220	2024-07-01	
10	Vice President Utility Operations	Debbie Powell	287,284	2024-05-06	
11	Vice President Policy and Resource Planning	Kristen Sheeran	339,447	2024-10-28	

FOOTNOTE DATA

(a) Concept: OfficerSalary

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

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	[a] Mark B. Ganz	Portland, Oregon		
2	Kathryn J. Jackson	Portland, Oregon		
3	[b] M. Lee Pelton	Portland, Oregon		
4	Maria M. Pope President and Chief Executive Officer	Portland, Oregon		
5	Marie Oh Huber	Portland, Oregon		
6	Michael H. Millegan	Portland, Oregon		
7	Michael L. Lewis	Portland, Oregon		
8	James P. Torgerson Chair of the Board	Portland, Oregon		
9	Dawn L. Farrell	Portland, Oregon		
10	Patricia S. Pineda	Portland, Oregon		
11	John O'Leary	Portland, Oregon		

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: NameAndTitleOfDirector

Term ended April 18, 2024

(b) Concept: NameAndTitleOfDirector

Term ended April 18, 2024

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☐ Yes ☐ No

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

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
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INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	☐ Yes ☑ No (Checked by default - Not explicitly defined)

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

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
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INFORMATION ON FORMULA RATES - Formula Rate Variances

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

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
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Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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 18, 2024, issued an order in Docket No. ES24-17-000 that authorizes the Company to issue up to $900 million of short-term debt through February 6, 2026. 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.

On September 10, 2024, PGE entered into an amendment of its existing revolving credit facility that extended the scheduled expiration into September 2029. As of December 31, 2024, PGE had a $750 million revolving credit facility that provides the Company the ability to expand to $850 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 2024, PGE was in compliance with this covenant with a 55.1% 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, 2024, PGE had no borrowings outstanding and there were no letters of credit issued. As a result, the aggregate unused available credit capacity under the revolving credit facility was $750 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, 2024, 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 four letter of credit facilities that provide a total capacity of $320 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, letters of credit for a total of $85 million were outstanding as of December 31, 2024. Outstanding letters of credit are not reflected on the Company's Comparative Balance Sheet.

On February 22, 2024, PGE entered into a Bond Purchase Agreement related to the sale of $450 million in First Mortgage Bonds (FMBs). The Bonds were issued and funded in full on February 22, 2024 and consist of:

- a series, due in 2029, in the amount of $100 million that will bear interest from its issuance date at an annual rate of 5.15%;
- a series, due in 2034, in the amount of $100 million that will bear interest from its issuance date at an annual rate of 5.36%; and;
- a series, due in 2054, in the amount of $250 million that will bear interest from its issuance date at an annual rate of 5.73%.

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 November 15, 2024, the Company made a scheduled $80 million repayment of a 3.51% Series First Mortgage Bond with a portion of the proceeds from the Term Loan described in the following paragraph.

Term Loan--On November 14, 2024, PGE obtained a 366-day term loan from lenders in the aggregate principal of $300 million under a 366-Day Bridge Credit Agreement. Pursuant to the Agreement, on November 14, 2024, the Company drew a loan from the lenders in the aggregate principal of $220 million. 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 80.0 basis points. The interest rate is subject to adjustment pursuant to the terms of the loan. On December 31, 2024, PGE repaid $50 million of the term loan, leaving an outstanding balance of $170 million.

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. In connection with the agreement to transfer certain tax credits generated in 2023 and 2024, PGE provided indemnification against the buyer's losses related to a failure to satisfy the PTC and ITC qualification or transferability requirements under the Internal Revenue Code, but not due to the action or legal tax status of the buyer or a change in tax law. As of December 31, 2024, 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:

Governmental Investigations

In March, April and May 2021, the Division of Enforcement of the Commodity Futures Trading Commission (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.

During 2024, PGE entered into a settlement agreement with the SEC in connection with its investigation. In connection with that settlement, on September 4, 2024, the SEC entered an administrative cease-and-desist order for violations of Sections 13(b)(2)(A) and 13(b)(2)(B) of the Securities Exchange Act of 1934, as amended, and Rule 13a-15(a) thereunder. These violations relate to the sufficiency of the Company's internal accounting controls, books and records and disclosure controls and procedures regarding the accounting for derivatives and regulatory transactions. The settlement did not include any monetary penalties.

The SEC's administrative order recognized numerous remedial measures promptly undertaken by PGE and its cooperation during the investigation. Such remedial measures, which were adopted by the Company in 2020 based on the recommendations of an independent committee of PGE's Board of Directors, included enhancements to the oversight of energy trading and associated risk management reporting, policies and practices.

Management cannot at this time predict whether there will be any further developments related to the CFTC or FERC investigations..

Colstrip-Related Litigation

The Company has a 20% ownership interest in Colstrip Units 3 and 4 coal-fired generating plant (Colstrip), which is located in the state of Montana and operated by one of the co-owners, Talen Montana, LLC. 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, along with other matters related to Colstrip, are summarized below.

Arbitration--In March 2021, co-owner NorthWestern Corporation 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. The parties have agreed to stay the arbitration proceedings indefinitely as settlement discussions are underway. PGE cannot predict the ultimate outcome of this matter.

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 alleged they had suffered adverse effects from the defendants' coal dust. In August 2021, the claim was amended to add PGE as a defendant. Plaintiffs sought 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 trial date had been rescheduled for June 2, 2025. In March 2025, the Company reached a settlement in principle with the plaintiffs that would not have a material impact to the Company's results of operations, financial condition, or cash flows.

10. None

11. (Reserved)

12. None

13. Changes in Officers:

On May 6, 2024, Debbie Powell joined the Company as Vice President of Utility Operations.

On July 1, 2024, John McFarland joined the Company as Vice President, Chief Commercial and Customer Officer.

On October 1, 2024, Brett Sims, Vice President, Energy Supply and Resource Strategy retired.

Effective October 28, 2024, Kristen Sheeran was promoted to Vice President, Policy and Resource Planning.

Changes in Directors:

Effective January 1, 2024, John O'Leary joined the Board to serve as a director until the next annual meeting of stockholders held on April 19, 2024 at which time he was reelected.

The number of directors on the Board decreased from eleven to nine effective as of the 2024 annual shareholder's meeting held on April 19, 2024, at which time, Mark Ganz and Lee Pelton retired from the Board.

14. None

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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	15,111,925,280	13,294,752,697
3	Construction Work in Progress (107)	200	569,951,129	974,517,848
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		15,681,876,409	14,269,270,545
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	6,196,192,797	5,851,760,350
6	Net Utility Plant (Enter Total of line 4 less 5)		9,485,683,612	8,417,510,195
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)		9,485,683,612	8,417,510,195
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		2,892,161	2,916,261
19	(Less) Accum. Prov. for Depr. and Amort. (122)		549,606	511,360
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224	86,245,684	84,967,379
23	Noncurrent Portion of Allowances	228	0	0
24	Other Investments (124)		13,246,789	9,097,650
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		69,963,786	73,077,737
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		2,161,907	11,107,353
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		173,960,721	180,655,020
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		460,719	4,569,354
36	Special Deposits (132-134)		125,094,853	92,079,229
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		12,000,000	96,842
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		231,923,765	219,789,679
41	Other Accounts Receivable (143)		58,056,268	64,204,830
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		11,815,522	9,443,726

43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		1,786,663	1,890,454
45	Fuel Stock (151)	227	21,338,923	28,001,414
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	87,914,386	78,836,409
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	513,783	2,111,148
53	(Less) Noncurrent Portion of Allowances	228	0	0
54	Stores Expense Undistributed (163)	227	4,343,197	3,950,888
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)		98,995,958	78,543,398
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)		177,284,816	138,282,759
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		34,395,859	32,622,968
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		2,161,907	11,107,353
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)		840,131,761	724,428,293
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		14,608,223	13,455,185
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	160,790,054	138,708,705
72	Other Regulatory Assets (182.3)	232	724,330,912	613,582,050
73	Prelim. Survey and Investigation Charges (Electric) (183)		10,522,530	3,537,042
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)		(9)	14,768
77	Temporary Facilities (185)		36,671	0
78	Miscellaneous Deferred Debits (186)	233	9,730,684	8,502,469
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)		14,986,918	16,085,911
82	Accumulated Deferred Income Taxes (190)	234	590,385,635	573,553,162
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,525,391,618	1,367,439,292
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		12,025,167,712	10,690,032,800

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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	2,122,277,163	1,753,903,725
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	1,676,875,055	1,568,996,980
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	8,706,023	7,427,718
13	(Less) Reacquired Capital Stock (217)	250	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(3,855,949)	(4,999,964)
16	Total Proprietary Capital (lines 2 through 15)		3,799,678,478	3,321,004,645
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	4,368,800,000	3,998,800,000
19	(Less) Reacquired Bonds (222)	256	0	0
20	Advances from Associated Companies (223)	256	0	0
21	Other Long-Term Debt (224)	256	170,000,000	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		281,074	305,471
24	Total Long-Term Debt (lines 18 through 23)		4,538,518,926	3,998,494,529
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		588,409,041	332,552,355
27	Accumulated Provision for Property Insurance (228.1)		300,000	0
28	Accumulated Provision for Injuries and Damages (228.2)		5,896,183	6,675,302
29	Accumulated Provision for Pensions and Benefits (228.3)		225,147,883	263,566,512
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		2,705,614	8,073,398
32	Long-Term Portion of Derivative Instrument Liabilities		71,721,254	74,459,595
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		309,492,546	285,151,269
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,203,672,521	970,478,431
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		0	145,811,136
38	Accounts Payable (232)		478,425,863	470,087,386
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		12,155,943	11,403,070
41	Customer Deposits (235)		26,675,753	25,601,775

42	Taxes Accrued (236)	262	19,197,791	12,211,988
43	Interest Accrued (237)		48,514,317	39,954,525
44	Dividends Declared (238)		57,371,089	50,595,253
45	Matured Long-Term Debt (239)		0	0
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		21,945,265	22,492,203
48	Miscellaneous Current and Accrued Liabilities (242)		46,682,459	46,939,573
49	Obligations Under Capital Leases-Current (243)		59,172,193	24,913,668
50	Derivative Instrument Liabilities (244)		219,038,315	238,759,624
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		71,721,254	74,459,595
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)		917,457,734	1,014,310,606
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		605,021	0
57	Accumulated Deferred Investment Tax Credits (255)	266	60,671,318	497,448
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	27,080,559	36,787,807
60	Other Regulatory Liabilities (254)	278	320,924,678	286,202,265
61	Unamortized Gain on Reacquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		944,427,755	876,069,126
64	Accum. Deferred Income Taxes-Other (283)		212,130,722	186,187,943
65	Total Deferred Credits (lines 56 through 64)		1,565,840,053	1,385,744,589
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		12,025,167,712	10,690,032,800

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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

Do not report fourth quarter data in columns (e) and (f)
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.
Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
Use page 122 for important notes regarding the statement of income for any account thereof.
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.
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.
If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
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.
Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
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	3,460,714,742	2,966,551,020			3,460,714,742	2,966,551,020				
3	Operating Expenses											
4	Operation Expenses (401)	320	2,003,804,192	1,739,144,236			2,003,804,192	1,739,144,236				
5	Maintenance Expenses (402)	320	274,450,195	222,811,863			274,450,195	222,811,863				
6	Depreciation Expense (403)	336	392,816,166	361,540,625			392,816,166	361,540,625				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	13,420,449	3,635,829			13,420,449	3,635,829				
8	Amort. & Depl. of Utility Plant (404-405)	336	79,219,629	65,864,461			79,219,629	65,864,461				
9	Amort. of Utility Plant Acq. Adj. (406)	336	0	0			0	0				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		1,899,953	(82,944)			1,899,953	(82,944)				
11	Amort. of Conversion Expenses (407.2)		0	0			0	0				
12	Regulatory Debits (407.3)		21,600,074	24,239,596			21,600,074	24,239,596				
13	(Less) Regulatory Credits (407.4)		16,653,804	3,402,683			16,653,804	3,402,683				
14	Taxes Other Than Income Taxes (408.1)	262	173,230,151	161,434,174			173,230,151	161,434,174				
15	Income Taxes - Federal (409.1)	262	5,845,379	9,247,886			5,845,379	9,247,886				
16	Income Taxes - Other (409.1)	262	13,653,558	25,127,505			13,653,558	25,127,505				
17	Provision for Deferred Income Taxes (410.1)	234, 272	830,068,797	471,976,889			830,068,797	471,976,889				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	872,487,715	466,804,780			872,487,715	466,804,780				
19	Investment Tax Credit Adj. - Net (411.4)	266	60,295,123	0			60,295,123	0				
20	(Less) Gains from Disp. of Utility Plant (411.6)		0	0			0	0				
21	Losses from Disp. of Utility Plant (411.7)		0	0			0	0				
22	(Less) Gains from Disposition of Allowances (411.8)		0	0			0	0				
23	Losses from Disposition of Allowances (411.9)		0	0			0	0				
24	Accretion Expense (411.10)		3,163,181	2,946,089			3,163,181	2,946,089				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,984,325,328	2,617,678,746			2,984,325,328	2,617,678,746	0	0	0	0
27	Net Util Oper Inc (Enter Tot line 2 less 25)		476,389,414	348,872,274			476,389,414	348,872,274	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)		0	0								
33	Revenues From Nonutility Operations (417)		3,769,578	2,900,050								
34	(Less) Expenses of Nonutility Operations (417.1)		7,021,690	5,101,217								
35	Nonoperating Rental Income (418)		308,684	221,616								
36	Equity in Earnings of Subsidiary Companies (418.1)	119	1,278,305	1,075,032								
37	Interest and Dividend Income (419)		5,954,821	4,027,081								
38	Allowance for Other Funds Used During Construction (419.1)		23,190,377	19,200,081								
39	Miscellaneous Nonoperating Income (421)		17,884,638	16,263,135								
40	Gain on Disposition of Property (421.1)		0	0								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		45,364,713	38,585,778								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)											
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		2,448,733	2,085,895								
46	Life Insurance (426.2)		(1,865,398)	(2,695,608)								
47	Penalties (426.3)		217,991	26,119								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,683,614	1,187,925								
49	Other Deductions (426.5)		11,437,125	4,974,782								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		13,922,065	5,579,113								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	414,051	427,618								
53	Income Taxes-Federal (409.2)	262	(4,248,414)	1,390,231								
54	Income Taxes-Other (409.2)	262	(1,813,370)	593,999								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	8,217,792	4,895,268								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	2,702,006	2,279,544								
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)		(131,947)	5,027,572								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		31,574,595	27,979,093								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		195,186,585	153,441,203								
63	Amort. of Debt Disc. and Expense (428)		1,539,130	1,593,767								
64	Amortization of Loss on Reaquired Debt (428.1)		1,104,802	1,260,409								
65	(Less) Amort. of Premium on Debt-Credit (429)		0	0								
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		0	2,013								
67	Interest on Debt to Assoc. Companies (430)		0	0								
68	Other Interest Expense (431)		9,172,712	10,494,708								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		15,344,389	12,742,176								
70	Net Interest Charges (Total of lines 62 thru 69)		191,658,840	154,045,898								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		316,305,169	222,805,469								

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)		316,305,169	222,805,469								

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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		1,565,144,187	1,531,490,255
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1				
4.2				
4.3				
4.4				
4.5				
4.6				
4.7				
4.8				
4.9				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1				
10.2				
10.3				
10.4				
10.5				
10.6				
10.7				
10.8				
10.9				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		315,026,864	221,730,437
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	(207,148,789)	(188,076,505)
30.2				
30.3				
30.4				
30.5				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(207,148,789)	(188,076,505)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,673,022,262	1,565,144,187
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)		1,676,875,055	1,568,996,980
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		7,427,718	6,352,686
50	Equity in Earnings for Year (Credit) (Account 418.1)		1,278,305	1,075,032
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)		8,706,023	7,427,718

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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)	316,305,169	222,805,469
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	485,456,244	431,040,915
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Debt Discount	2,643,932	2,852,163
5.2	Amortization of Unrecovered Plant	1,899,953	(82,944)
5.3	Net Price Risk Management Activities	(21,494,200)	399,376,003
8	Deferred Income Taxes (Net)	(36,903,130)	7,787,833
9	Investment Tax Credit Adjustment (Net)	0	0
10	Net (Increase) Decrease in Receivables	70,145,639	8,219,063
11	Net (Increase) Decrease in Inventory	(1,210,430)	(17,945,387)
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	53,577,232	(177,058,522)
14	Net (Increase) Decrease in Other Regulatory Assets	(98,593,793)	(359,725,699)
15	Net Increase (Decrease) in Other Regulatory Liabilities	9,204,285	4,350,066
16	(Less) Allowance for Other Funds Used During Construction	23,190,377	19,200,081
17	(Less) Undistributed Earnings from Subsidiary Companies	1,278,305	1,075,032
18	Other (provide details in footnote):		
18.1	Other: Margin and Customer Deposits	(31,941,646)	(104,687,601)
18.2	Other: Operating	[(a)] 52,360,690	[(c)] 15,510,800
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	776,981,263	412,167,046
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,291,637,940)	(1,373,225,203)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	(23)	(46,035)
30	(Less) Allowance for Other Funds Used During Construction	(23,190,377)	(19,200,081)
31	Other (provide details in footnote):		
31.1	Other Capital Activities	[(b)] (32,948,158)	[(d)] (10,646,117)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,301,395,744)	(1,364,717,274)
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	0	2,029,983
53.2	Other Investments	5,296,755	6,318,294
53.3	Purchases of Trojan Decommissioning Securities	(7,836,629)	(654,830)
53.4	Sales of Trojan Decommissioning Securities	1,998,350	608,496
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,301,937,268)	(1,356,415,331)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	670,000,000	600,000,000
62	Preferred Stock		
63	Common Stock	341,136,729	479,821,663
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)	0	145,811,136
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,011,136,729	1,225,632,799
72	Payments for Retirement of:		
73	Long-term Debt (b)	(130,000,000)	(260,000,000)
74	Preferred Stock		
75	Common Stock	0	0
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):	0	0
76.2	Debt Issue Costs	(3,084,323)	(3,334,540)
78	Net Decrease in Short-Term Debt (c)	(145,811,136)	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(199,490,742)	(179,050,329)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	532,750,528	783,247,930
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)	7,794,523	(161,000,355)
88	Cash and Cash Equivalents at Beginning of Period	4,666,196	165,666,551
90	Cash and Cash Equivalents at End of Period	12,460,719	4,666,196

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Amounts relate primarily to increase in deferred investment tax credits

(b) Concept: OtherConstructionAndAcquisitionOfPlantInvestmentActivities

Amounts primarily relate to cost of removal activity.

(c) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Amounts relate primarily to stock compensation expense.

(d) Concept: OtherConstructionAndAcquisitionOfPlantInvestmentActivities

Amounts primarily relate to cost of removal activity.

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 Commission 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)	$ 4,569,354	$ 460,719
Temporary Cash Investments (136)	96,842	12,000,000
	$ 4,666,196	$ 12,460,719

	2023	2024
Cash paid during the year:		
Interest	$ 148,942,136	$ 188,977,140
Allowance for borrowed funds used during construction	(12,742,176)	(15,344,389)
	$ 136,199,960	$ 173,632,751
Income taxes (received)	$ 11,535,794	$ (89,805,127)
Non-cash investing and financing activities:		
Accrued capital additions	$ 212,428,061	$ 184,079,067
Accrued dividends payable	$ 50,595,253	$ 57,371,089
Preliminary engineering transferred to Construction work in progress	$ 513,239	$ 2,535,276

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 meet the needs of, and obtain reasonably-priced power for its retail customers, manage risk, and administer its long-term wholesale contracts. In addition, PGE performs portfolio management and wholesale market sales services for third parties in the region. The Company 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, 2024, PGE served approximately 950 thousand retail customers with a service area population of approximately 1.9 million.

As of December 31, 2024, PGE had 2,915 employees in its workforce, with 648 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. One agreement covers 582 employees and expires February 2028, and the other covers 66 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, 2024 up to February 14, 2025, the date that the Company's U.S. GAAP financial statements were issued, and has updated such evaluation for disclosure purposes through April 11, 2025. 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 $12 million as of December 31, 2024 and none as of December 31, 2023 reflected 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 eight calendar 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 calendar 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 receivable and unbilled revenues related to retail sales are charged to Administrative and General Expenses and are recorded in the same period as the related 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.

Provisions for Uncollectible Accounts receivable 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 2024 or 2023.

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 prices. 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 $125 million as of December 31, 2024 and $92 million as of December 31, 2023. Letters of credit provided as collateral are not recorded on the Company's Comparative Balance Sheet and there were $18 million and $40 million as of December 31, 2024 and 2023, 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 performed under long-term service agreements 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 related to recently completed plant that are 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 (GRC) for equity funds and the cost of actual borrowings for debt funds.

AFUDC is capitalized as part of the cost of plant and credited to the Statement of Income. The average rate used by PGE was 6.7% in 2024 and 6.5% in 2023. AFUDC from borrowed funds, reflected as a reduction to Interest Charges, was $15 million in 2024 and $13 million in 2023. AFUDC from equity funds, included in Other Income, was $23 million in 2024 and $19 million in 2023.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation Expense as a percent of the related average depreciable plant in service was 3.5% in 2024 and 3.4% in 2023. 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	96
Wind	31
Transmission	61
Distribution	52
Energy Storage	18
General	17

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 three, 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 $611 million and $558 million as of December 31, 2024 and 2023, respectively, with amortization expense of $72 million in 2024 and $61 million in 2023. Future estimated amortization expense as of December 31, 2024 is as follows: $70 million in 2025; $62 million in 2026; $56 million in 2027; $33 million in 2028; and $13 million in 2029.

Marketable Securities

Nuclear decommissioning trust

The Nuclear decommissioning trust (NDT) 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 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

PGE's non-qualified benefit plans (NQBP) reflects assets held in trust to cover the obligations of PGE's 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 assets 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: i) probable future reductions in revenue associated with amounts that are expected to be credited to customers through the ratemaking process; or ii) current collections for future expected costs. 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 includes 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 2024 and 2023.

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, 2024, PGE's actual NVPC was $78 million below baseline NVPC, which is outside the established deadband range. Pursuant to the PCAM and related earnings test, because PGE's preliminary regulatory ROE was below 10.5%, there is no estimated refund to customers under the PCAM for 2024. For the year ended December 31, 2023, actual NVPC was above baseline NVPC by $5 million, which was within the established deadband range, therefore no estimated collection from customers was recorded as of December 31, 2023.

The Company also has a reliability contingency event (RCE) mechanism, which operates under the PCAM tariff. This mechanism was approved by the OPUC as part of the 2024 GRC proceedings. The RCE mechanism allows PGE to defer and recover 80% of prudent costs for RCEs above amounts forecasted in the Company's Annual Power Cost Update Tariff (AUT), without application of an earnings test, with the remaining 20% flowing through operating expenses and subject to the existing PCAM.

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 customer prices is recorded as a regulatory asset or liability in the Company's Comparative Balance Sheet. As of December 31, 2024, PGE had a net regulatory asset related to Utility Plant AROs in the amount of $7 million and a net regulatory asset related to Trojan decommissioning ARO activities of $161 million. As of December 31, 2023, PGE had a net regulatory liability related to Utility Plant AROs in the amount of $4 million and a net regulatory asset related to Trojan decommissioning ARO activities of $139 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 19, 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 NQBP 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 $63 million in 2024 and $56 million in 2023.

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, net in the Company's Comparative Balance Sheet, is calculated based on actual net retail system load each month, the number of days from the last meter read date through the last day of the month, and current customer prices.

As a rate-regulated utility, PGE, in certain situations, recognizes Operating Revenue to be billed to customers in future periods or defers the recognition of certain Operating Revenues to the period in which the related costs are incurred or approved by the OPUC for amortization. For additional information, see "*Regulatory Assets and Liabilities*" in this Note 2.

Stock-Based Compensation

The measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, is based on the estimated fair value of the awards. The fair value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite vesting period. PGE attributes the value of stock-based compensation to expense on a straight-line basis.

Beginning with 2020 awards, time-based and performance-based restricted stock unit (RSU) grant agreements provide that, if a grantee satisfies the "rule of 75" upon termination of employment for reasons other than cause, then: i) in the case of time-based RSUs, all unvested awards will vest; and ii) in the case of performance-based RSUs, the grantee will be eligible for full vesting, based on performance results, notwithstanding early termination. For purposes of these provisions, a recipient satisfies the rule of 75 if the recipient has no less than 5 years of service and the recipient's age plus years of service is at least 75. PGE accelerates recognition of compensation cost to the date the rule of 75 is met if the date is earlier than the vesting date of the award.

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. Investment Tax Credits (ITC) are deferred and amortized as a reduction of income tax expense over the estimated useful lives of the related properties. The weighted average life of the related properties is 19 years as of December 31, 2024. Any valuation allowance would be established to reduce deferred tax assets to the "more likely than not" amount expected to be realized upon transfer or in future tax returns. Valuation allowances related to a discount incurred on transfer transactions that are recorded to deferred tax expense are currently recoverable through a regulatory asset.

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.

The Inflation Reduction Act of 2022 (IRA) was signed into law on August 16, 2022. The IRA provides an election to transfer (i.e., sell) certain tax credits to unrelated third parties in exchange for cash consideration. PGE has elected an accounting policy to account for the transfer of Federal production tax credits (PTCs) and ITCs, including discounts, within the scope of Accounting Standards Codification 740 - Income Taxes. On December 12, 2023, PGE received approval from the OPUC to transfer 2023 PTCs and record any difference between the full value and the discounted value as a deferred regulatory asset. On April 17, 2024, PGE received approval from the OPUC to transfer 2024 and 2025 PTCs and record any difference between the full value and the discounted value as a deferred regulatory asset. On December 11, 2024, PGE received approval from the OPUC to transfer 2024 ITCs and return the net proceeds from the sale to PGE customers. Proceeds from the sale of 2023 PTCs and 2024 PTCs and ITCs are reported in Tax credit sales on PGE's statements of cash flows. PGE presents the cash proceeds in the Statement of Cash Flows under Cash received from income taxes, net within the supplemental disclosures of cash flow information. PGE transferred tax credits, net of discounts, of $112 million and $24 million for cash proceeds in 2024 and 2023, respectively. The 2024 proceeds include $52 million from PTC sales and $60 million from ITC sales, net of discounts. Derecognition of the transferred deferred tax asset occurs when the buyer obtains control of the tax credit.

Recent Accounting Pronouncements

In December 2023, the FASB issued Accounting Standards Update (ASU) 2023-09 *Income Taxes (Topic 740): Improvements to Income Tax Disclosures*. ASU 2023-09 amends Topic 740 to address requests to improve transparency about income tax information through improvements to income tax disclosures primarily related to the rate reconciliation and income taxes paid information. For calendar year-end entities, the update will be effective for annual periods beginning on January 1, 2025. Early adoption is permitted. PGE does not expect the adoption to have a material impact on the financial statements and has not early adopted the standard.

In November 2024, the FASB issued ASU 2024-03 *Income Statement--Reporting Comprehensive Income--Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses*. ASU 2024-03 requires additional disclosure, in the notes to financial statements, of specified information about certain costs and expenses. For calendar year-end entities, the update will be effective for annual periods beginning on January 1, 2027. Early adoption is permitted. PGE is assessing the impact of adoption on the financial statements and does not plan to early adopt the standard.

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,	
	2024	2023
Balance as of beginning of year	$ 9	$ 12
Increase in provision	11	5
Amounts written off, less recoveries	(8)	(8)
Balance as of end of year	$ 12	$ 9

Net Utility Plant

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

	As of December 31,	
	2024	2023
Utility Plant:		
Generation	$ 5,456	$ 4,918
Transmission	1,400	1,141
Distribution	6,191	5,251
General	986	977
Intangible	1,007	960
Total in service	15,040	13,247
Accumulated Provision for Depreciation, Amortization, and Depletion	(6,196)	(5,852)
Total in service, net	8,844	7,395
Held for future use	72	48
Construction Work In Progress *	570	975
Net Utility Plant	$ 9,486	$ 8,418

*The PGE-owned portion of the Clearwater Wind Development, with $411 million in CWIP as of December 31, 2023, was placed in-service on January 5, 2024.

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, 2024 and 2023, 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, 2024				
	Level 1	Level 2	Level 3	Other(2)	Total
Assets:					
Temporary Cash Investments	$ 12	$ --	$ --	$ --	$ 12
Nuclear decommissioning trust: (1)					
Debt securities:					
Domestic government	10	6	--	--	16
Corporate credit	--	7	--	--	7

	Level 1	Level 2	Level 3	Other	Total
Money market funds measured at NAV (2)	--	--	--	7	7
Non-qualified benefit plan trust: (3)					
Debt securities--domestic government	2	--	--	--	2
Paid Leave Oregon Trust:					
Money market funds measured at NAV (2)	--	--	--	4	4
Price risk management activities: (1) (4)					
Electricity	--	18	1	--	19
Natural gas	--	15	--	--	15
	$ 24	$ 46	$ 1	$ 11	$ 82
Liabilities:					
Price risk management activities: (1) (4)					
Electricity	$ --	$ 25	$ 31	$ --	$ 56
Natural gas	--	159	4	--	163
	$ --	$ 184	$ 35	$ --	$ 219

(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 $32 million, which are recorded at cash surrender value.
(4)For further information regarding price risk management derivatives, see Note 5, Risk Management.

	December 31, 2023				
	Level 1	Level 2	Level 3	Other(2)	Total
Assets:					
Temporary Cash Investments	$ --	$ --	$ --	$ --	$ --
Nuclear decommissioning trust: (1)					
Debt securities:					
Domestic government	9	9	--	--	18
Corporate credit	--	7	--	--	7
Money market funds measured at NAV (2)	--	--	--	6	6
Non-qualified benefit plan trust: (3)					
Money market funds	2	--	--	--	2
Debt securities--domestic government	3	--	--	--	3
Paid Leave Oregon Trust:					
Money market funds measured at NAV (2)	--	--	--	3	$ 3
Price risk management activities: (1) (4)					
Electricity	--	8	14	--	22
Natural gas	--	11	--	--	11
	$ 14	$ 35	$ 14	$ 9	$ 72
Liabilities:					
Price risk management activities: (1) (4)					
Electricity	$	$	$	$	$

	--	30	43	--	73
Natural gas	--	150	16	--	166
	$ --	$ 180	$ 59	$ --	$ 239

(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 $30 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, NQBP, and Paid Leave Oregon 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.

Money market funds--PGE invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, certificates of deposits, and commercial paper. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value. Redemption is permitted daily without written notice.

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

Assets and liabilities from price risk management activities, recorded at fair value in PGE's Comparative Balance Sheet, consist of derivative instruments entered into by the Company to manage its risk exposure to commodity price and foreign currency exchange rates and reduce volatility in NVPC. For additional information regarding these assets and liabilities, see Note 5, Risk Management.

For those assets and liabilities from price risk management activities classified as Level 2, fair value is derived using present value formulas that utilize inputs such as forward commodity prices and interest rates. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include commodity forwards, futures, and swaps.

Assets and liabilities from price risk management activities classified as Level 3 consist of instruments for which fair value is derived using one or more significant inputs that are not observable for the entire term of the instrument. These instruments consist of longer-term commodity forwards, futures, and swaps.

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

Commodity Contracts	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Price per Unit Low	Price per Unit High	Price per Unit Weighted Average
	(in millions)						
As of December 31, 2024:							
Electricity physical forwards	$ --	$ 28	Discounted cash flow	Electricity forward price (per MWh)	$ 14.00	$ 99.68	$ 59.43
Natural gas financial swaps	--	4	Discounted cash flow	Natural gas forward price (per Dth)	1.86	6.53	2.68
Electricity financial futures	1	3	Discounted cash flow	Electricity forward price (per MWh)	27.00	110.00	70.55
	$ 1	$ 35					
As of December 31, 2023:							
Electricity physical forwards	$ 14	$ 43	Discounted cash flow	Electricity forward price (per MWh)	$ 37.53	$ 153.33	$ 84.58
Natural gas financial swaps	--	16	Discounted cash flow	Natural gas forward price (per Dth)	2.25	8.89	3.37
Electricity financial futures	--	--	Discounted cash flow	Electricity forward price (per MWh)	65.30	107.31	91.33
	$ 14	$ 59					

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, 2024	2023
Net liabilities from price risk management activities as of beginning of year	$ 45	$ 32
Net realized and unrealized losses *	25	26
Net transfers from Level 3 to Level 2	(36)	(13)
Net liabilities from price risk management activities as of end of year	$ 34	$ 45
Level 3 net unrealized losses/(gains) that have been fully offset by the effect of regulatory accounting	$ 30	$ 17

* Includes $5 million in net realized gains in 2024 and $9 million in net realized losses in 2023.

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers into and out of Level 3 at the end of the reporting period for all of its derivative instruments.

During the years ended December 31, 2024 and 2023, there were no transfers into Level 3 from Level 2. Transfers from Level 3 are reflected in the table above.

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, 2024, the carrying amount of PGE's long-term debt was $4,539 million and its estimated aggregate fair value was $3,963 million. As of December 31, 2023, the carrying amount of PGE's long-term debt was $3,999 million with an estimated aggregate fair value of $3,705 million.

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

NOTE 5: 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, and secure reasonably priced power for, 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. 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, 2024	2023
Current assets:		
Commodity contracts:		
Electricity	$ 18	$ 13
Natural gas	14	9
Total current derivative assets	32	22
Noncurrent assets:		
Commodity contracts:		
Electricity	1	9
Natural gas	1	2
Total noncurrent derivative assets	2	11
Total derivative assets	$ 34	$ 33
Current liabilities:		
Commodity contracts:		
Electricity	$ 32	$ 51
Natural gas	115	113
Total current derivative liabilities	147	164
Noncurrent liabilities:		
Commodity contracts:		
Electricity	24	22
Natural gas	48	53
Total noncurrent derivative liabilities	72	75

	2024	2023
Total derivative liabilities	$ 219	$ 239

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,	
	2024	2023
Commodity contracts:		
Electricity	2 MWh	3 MWh
Natural gas	199 Dth	213 Dth
Foreign currency contracts	$ 34 Canadian	$ 20 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, 2024, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $41 million, all of which was for natural gas, for which PGE has posted $16 million collateral. As of December 31, 2023, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $28 million, entirely for natural gas, for which PGE had posted $1 million collateral.

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,	
	2024	2023
Commodity contracts:		
Electricity	$ (17)	$ (130)
Natural Gas	30	357
Foreign currency contracts	(1)	(1)

Net unrealized and certain net realized losses (gains) presented in the table above are offset within the Statement of Income by the effects of regulatory accounting. Of the net amounts recognized in Net income, net gains of $5 million and net losses of $403 million for the years ended December 31, 2024 and 2023, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table presents the years in which the net unrealized losses recorded as of December 31, 2024 related to PGE's derivative activities would become realized as a result of the settlement of the underlying derivative instrument (in millions):

	2025	2026	2027	2028	2029	Thereafter	Total
Commodity contracts:							
Electricity	$ 13	$ 5	$ 3	$ 2	$ 2	$ 12	$ 37
Natural gas	101	43	4	--	--	--	148
Net unrealized loss	$ 114	$ 48	$ 7	$ 2	$ 2	$ 12	$ 185

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, 2024 was $194 million. The Company has posted $70 million in collateral, consisting entirely of cash. If the credit-risk-related contingent features underlying these agreements were triggered as of December 31, 2024, the cash requirement to either post as collateral or settle the instruments immediately would have been $126 million. As of December 31, 2024, PGE had $15 million cash collateral posted for derivative instruments with no credit-risk-related contingent features. Cash collateral for derivative instruments is classified as Special Deposits included in Other current assets on the Company's Comparative Balance Sheet.

As of December 31, 2024, PGE received from counterparties $29 million in collateral, consisting of $24 million of letters of credit and $5 million of cash. 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 5, 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,	
		2024	2023
Regulatory assets:			
Price risk management	(1)	$ 185	$ 206
Pension plans	(2)	84	104
Deferred income taxes		$ 59	56
February 2021 ice storm and damage	(5)	59	69
January 2024 storm and damage	2029	47	--
Reliability contingency events	(3)	92	--
2020 Labor Day wildfire	(3) 2029	24	29

		2024	2023
Wildfire mitigation	(4)	44	30
Other	Various	130	120
Total regulatory assets		$ 724	$ 614
Regulatory liabilities:			
Deferred income taxes	(5)	237	233
Clearwater RAC	(3)	40	--
Other	Various	44	53
Total regulatory liabilities		$ 321	$ 286

(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 period has yet to be decided.
(4)Amounts deferred between January 1, 2022 and May 8, 2022 are amortizing over a 2-year period beginning October 20, 2023. Incremental amounts deferred between January 1, 2023 and December 31, 2024 have not yet been approved for amortization.
(5)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.

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.

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.

January 2024 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 storm that ultimately led Oregon's Governor to declare a state of emergency in January 2024. The declared state of emergency allows PGE to seek recovery of incremental storm expenses through the OPUC pre-authorized emergency deferral mechanism, subject to the application of an earnings test. On February 9, 2024, PGE filed a Notice of Deferral with the OPUC, under Docket UM 2190, related to the emergency restoration costs for the January storm, and through December 31, 2024 the Company has deferred $46 million, including interest, under the deferral. As of December 31, 2024, PGE's preliminary regulated return on equity under the earnings test, based on actual results, did not exceed the OPUC's authorized rate. PGE believes the full amounts deferred as of December 31, 2024 are probable of recovery under the emergency deferral mechanism. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence, including application of the earnings test, 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.

Reliability contingency events represents costs deferred under the reliability contingency event (RCE) mechanism, which allows PGE to defer and recover 80% of prudent costs for RCEs above amounts forecasted in the Company's AUT, without application of an earnings test, with the remaining 20% flowing through operating expenses and subject to the existing PCAM. As of December 31, 2024, PGE's deferred balance related to RCEs was $90 million, which includes costs from multiple qualified RCEs during the year, but primarily associated with the January 2024 storm. PGE files the results of the PCAM annually with the OPUC no later than July 1, initiating a regulatory review process that typically results in a final determination and order from the OPUC by the end of the year of filing, with any resulting refund or collection impacting customer prices effective January 1 of the following year. Cost recovery related to the 80% of prudently incurred RCE costs incurred in 2024 are included as a part of the PCAM filing for 2024, which the Company expects to file no later than July 1, 2025. PGE believes the deferred amounts as of December 31, 2024 are probable of recovery. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence 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.

2020 Labor Day wildfire represents 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.

Wildfire mitigation represents incremental costs and investments made by PGE related to intensifying efforts on its system to mitigate the risk of wildfire and improve resiliency to wildfire damage under Oregon Senate Bill 762, enacted in 2021. These efforts include enhanced tree and brush clearing, hardening and undergrounding equipment, and making emergency plans in close partnership with various land and emergency management agencies to further expand the use of a public safety power shutoff, when the risk warrants. In December 2023, PGE submitted its 2024 risk-based Wildfire Mitigation Plan, which was approved by the OPUC during the public meeting on July 9, 2024.

As of December 31, 2024 and December 31, 2023, PGE's deferred balance related to wildfire mitigation was $43 million and $29 million, respectively. The 2024 balance is comprised of:

Pre-AAC--Prior to establishing the collections noted below, PGE had deferred incremental costs related to wildfire mitigation and as of December 31, 2024 this balance is $7 million. 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. In May 2023, in Order No. 23-173, the OPUC approved an automatic adjustment clause mechanism to recover wildfire mitigation costs (capital and expense). PGE and certain parties agreed to a stipulation, which was adopted by the OPUC in October 2023, that allowed PGE to begin amortizing $27 million comprised of $23 million related to the September 30, 2023 deferred operating expense balance of $31 million and $4 million for capital related revenue requirement.

2023 Base Rates--The outcome of PGE's 2022 GRC provided an annual amount of $24 million to be collected in base rates for recovery of operating expenses related to wildfire mitigation efforts beginning May 9, 2022, through December 31, 2023. As of December 31, 2024, there was $1 million in the balancing account. PGE submitted an advice filing in January 2025 requesting recovery of these costs, which has yet to be approved by the Commission.

2024 AAC--Beginning January 1, 2024, and in conjunction with the Company's 2024 GRC proceeding, PGE removed the $24 million of wildfire mitigation operations and maintenance (O&M) expense recovery from base rates, with the intent of recovering the current year forecasted O&M expense within the automatic adjustment clause (AAC) in a separate tariff. On February 16, 2024, PGE submitted an advice filing to the OPUC to update the tariff to reflect prospective wildfire mitigation costs for 2024, which included $45 million of O&M expense and $4 million for the revenue requirement of capital placed in service. On July 23, 2024, the OPUC reached a decision that allowed PGE to begin collecting $24 million of O&M expense and $4 million for the revenue requirement of capital placed in service. Collection will occur over a nine-month period, which began August 1, 2024. Although the approved amount of collections in 2024 is less than actual costs, PGE does not believe it is precluded from deferring such costs and believes they are prudently incurred and probable of recovery. Any differences between actual expense and customer collections will be recorded as regulatory assets or liabilities within the AAC balancing account, which will be subject to a prudency review, but will not be subject to an earnings test. As of December 31, 2024, there was $35 million deferred as a regulatory asset in the balancing account. The OPUC has significant discretion in making the final determination of recovery. The OPUC's conclusion of overall prudence 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.

PGE filed its 2025 Wildfire Mitigation Plan update on December 31, 2024, which includes a request to begin collecting $55 million related to O&M and $9 million related to the capital revenue requirement. The Company expects an OPUC decision on this request by March 1, 2025.

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.

Clearwater RAC represents all costs and benefits associated with the Clearwater wind facility, which, for 2024, represents a net benefit.

The RAC allows PGE to recover prudently incurred costs of renewable resources through filings made each year, outside of a GRC. Under the RAC, during 2023, the Company submitted a filing for Clearwater, which estimated the annual revenue requirement, net of NVPC benefits to be a refund to customers of approximately $30 million that would be included in customers prices June 1, 2024. Pursuant to the filing, PGE would defer the revenue requirement, net of NVPC benefits, from the in-service date of January 2024 until Clearwater was reflected in customer prices. The OPUC delayed the tariff effective date and issued an order on September 13, 2024 in Docket UE 427 that further suspended the tariff effective date until March 1, 2025 pending additional regulatory review. On December 20, 2024, the OPUC issued an order to exclude Clearwater from the 2025 GRC as prudency is being determined in a separate proceeding with target price effective date of March 1, 2025. PGE will continue to defer the revenue requirement, net of NVPC benefits until included in customer prices. PGE anticipates amortization to begin shortly after the rate effective date. As of December 31, 2024, the Company recorded a net $40 million regulatory liability, which represents the deferred revenue requirement that PGE believes is probable of recovery, net of NVPC that is probable of refund to customers under the RAC. The OPUC has significant discretion on overall prudence and in making the final determination of recovery or refund. Any cost disallowance or increased refunds would be recognized as a charge to earnings.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

AROs consist of the following (in millions):

	As of December 31,	
	2024	2023
Trojan decommissioning activities	$ 205	$ 174
Utility Plant	80	85
Non-utility property	25	27
Total asset retirement obligations	310	286
Less: current portion *	18	14
Noncurrent asset retirement obligations	$ 292	$ 272

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 2024, the Company recorded an increase in the ARO of $32 million due to an increase in expected annual ISFSI operation costs. The Company also recorded Accretion Expense of $8 million and a reduction of $9 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 $22 million in 2024 for costs incurred in 2023 and $9 million in 2023 for costs incurred in 2022 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 2024, utility AROs decreased by $5 million, with the change comprised of a reduction of $4 million due to revisions in estimated cash flows, Accretion Expense of $3 million, and a reduction of $4 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,	
	2024	2023
Balance as of beginning of year	$ 286	$ 289
Liabilities incurred	--	2
Liabilities settled	(16)	(25)
Accretion Expense	12	11
Revisions in estimated cash flows	28	9
Balance as of end of year	$ 310	$ 286

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 NDT 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

On September 10, 2024, PGE entered into an amendment of its existing revolving credit facility that extended the scheduled expiration into September 2029. As of December 31, 2024, PGE had a $750 million revolving credit facility that provides the Company the ability to expand to $850 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, 2024, PGE was in compliance with this covenant with a 55.1% 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.

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, 2024, PGE had no commercial paper outstanding.

Under the revolving credit facility, as of December 31, 2024, PGE had no borrowings outstanding and there were no letters of credit issued. As a result, the aggregate unused available credit capacity under the revolving credit facility was $750 million.

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 four letter of credit facilities that provide a total capacity of $320 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 $85 million of letters of credit were outstanding as of December 31, 2024. 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, 2026.

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

	Year Ended December 31,	
	2024	2023
Average daily amount of short-term debt outstanding	$ 39	$ 63
Weighted daily average interest rate *	5.5 %	5.5 %
Maximum amount outstanding during the year	$ 319	$ 225

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

NOTE 9: LONG-TERM DEBT AND OTHER FINANCING ARRANGEMENTS

Long-term debt

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

	As of December 31,	
	2024	2023
First Mortgage Bonds, rates range from 1.82% to 6.88%, with a weighted average rate of 4.52% in 2024 and 4.32% in 2023, due at various dates through 2059.	$ 4,250	$ 3,880
Unsecured term bank loan, variable rate of 5.30% at December 31, 2024	170	--
Pollution Control Revenue Bonds, rates at 2.13% and 2.38%, due 2033	119	119
Total long-term debt	$ 4,539	$ 3,999

First Mortgage Bonds--On February 22, 2024, PGE entered into a Bond Purchase Agreement related to the sale of $450 million in FMBs. The Bonds were issued and funded in full on February 22, 2024 and consist of:

- a series, due in 2029, in the amount of $100 million that will bear interest from its issuance date at an annual rate of 5.15%;
- a series, due in 2034, in the amount of $100 million that will bear interest from its issuance date at an annual rate of 5.36%; and
- a series, due in 2054, in the amount of $250 million that will bear interest from its issuance date at an annual rate of 5.73%.

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 November 15, 2024, the Company made a scheduled $80 million repayment of a 3.51% Series First Mortgage Bond with a portion of the proceeds from the Term Loan described in the following paragraph.

Term Loan--On November 14, 2024, PGE obtained a 366-day term loan from lenders in the aggregate principal of $300 million under a 366-Day Bridge Credit Agreement. Pursuant to the Agreement, on November 14, 2024, PGE drew a loan from the lenders in the aggregate principal of $220 million. 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 80.0 basis points. The interest rate is subject to adjustment pursuant to the terms of the loan. On December 31, 2024, PGE repaid $50 million of the term loan, leaving an outstanding balance of $170 million.

Pollution Control Revenue Bonds--In March 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 that bear an interest rate of 2.125%, and $21 million aggregate principal 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, 2024, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:		
2025	$	170
2026		--
2027		160
2028		100
2029		200
Thereafter		3,909
	$	4,539

Pelton/Round Butte financing arrangement

Under terms of an 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 which was exercised in 2022. 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 in 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 records the tangible utility asset within Net Utility Plant on the Comparative Balance Sheet as if it were the legal owner and recognizes Depreciation Expense over the estimated useful life. The monthly PPA payments are split between Interest Charges and a reduction of the principal portion of the financing obligation, which is included in Other noncurrent liabilities. 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.

As of December 31, 2024, the future minimum payments on the financing arrangement are as follows (in millions):

Years ending December 31:		
2025	$	5
2026		5
2027		5
2028		5
2029		5
Thereafter		59
Total Payments		84
Less: Imputed Interest		(52)
Present value of minimum payments	$	32

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.

PGE made $16 million in contributions to the pension plan in 2024 and none in 2023 or 2022. PGE expects to contribute $22 million to the pension plan in 2025.

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 2023, PGE executed a sale of the retiree portion of the Nonrepresented Life Insurance Plan as well as a settlement of the active non-union portion of the Nonrepresented HRA Plan, resulting in a combined $1 million settlement gain, which has been recorded in Miscellaneous income, 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 5, Fair Value of Financial Instruments.

Other NQBP--In addition to the NQBP discussed above, PGE provides certain employees and outside directors with deferred compensation plans, whereby participants may defer a portion of their earned compensation. PGE holds investments in a NQBP trust that are intended to be a funding source for these plans.

Trust assets and plan liabilities related to the NQBP included in Other Special Funds in PGE's Comparative Balance Sheet are as follows as of December 31 (in millions):

	2024			2023		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust assets	$ 16	$ 18	$ 34	$ 17	$ 18	$ 35
Non-qualified benefit plan liabilities *	16	60	76	18	63	81

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,			
	2024		2023	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Growth securities	53 %	55 %	53 %	55 %
Liability Hedging Fixed Income securities	47	45	47	45
Total	100 %	100 %	100 %	100 %
Other Postretirement Benefit Plans:				
Equity securities	40 %	38 %	41 %	39 %
Debt securities	60	62	59	61
Total	100 %	100 %	100 %	100 %
Non-Qualified Benefits Plans:				
Equity securities	1 %	2 %	1 %	4 %
Debt securities	6	5	13	10
Insurance contracts	93	93	86	86
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, 2024:					
Defined Benefit Pension Plan assets:					
Equity securities--Domestic	$ 13	$ --	$ --	$ --	$ 13
Investments measured at NAV:					
Money market funds	--	--	--	30	30
Collective trust funds	--	--	--	440	440
Private equity funds	--	--	--	1	1
	$ 13	$ --	$ --	$ 471	$ 484
Other Postretirement Benefit Plans assets:					
Equity securities:					
Domestic	--	2	--	--	2
International	4	--	--	--	4
Debt securities--Domestic	--	4	--	--	4
Investments measured at NAV:					
Money market funds	--	--	--	11	11
Collective trust funds	--	--	--	4	4
	$ 4	$ 6	$ --	$ 15	$ 25
As of December 31, 2023:					
Defined Benefit Pension Plan assets:					
Equity securities--Domestic	$ 14	$ --	$ --	$ --	$ 14
Investments measured at NAV:					
Money market funds	--	--	--	30	30
Collective trust funds	--	--	--	484	484

Private equity funds	--	--	--	2	2
	$ 14	$ --	$ --	$ 516	$ 530
Other Postretirement Benefit Plans assets:					
Money market funds	$ 3	$ --	$ --	$ --	$ 3
Equity securities:					
Domestic	--	2	--	--	2
International	4	--	--	--	4
Debt securities--Domestic government	--	4	--	--	4
Investments measured at NAV:					
Money market funds	--	--	--	6	6
Collective trust funds	--	--	--	4	4
	$ 7	$ 6	$ --	$ 10	$ 23

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

An overview of the identification of Level 1, 2, and 3 financial instruments is provided in Note 5, Fair Value of Financial Instruments. The following discussion provides information regarding the methods used in valuation of the various asset class investments held in the pension and other postretirement benefit plan trusts.

Money market funds--PGE invests in money market funds that seek to maintain a stable NAV. These funds invest in high-quality, short-term, diversified money market instruments, short-term treasury bills, federal agency securities, or certificates of deposit. Some of the money market funds held in the trusts are classified as Level 1 instruments as pricing inputs are based on unadjusted prices in an active market. The remaining money market funds are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

Equity securities--Equity mutual fund and common stock securities are classified as Level 1 securities as pricing inputs are based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and NYSE. Mutual fund assets included in separately managed accounts are classified as Level 2 securities due to pricing inputs that are directly or indirectly observable in the marketplace.

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

Collective trust funds--Domestic and international mutual fund assets and debt security assets, including municipal debt and corporate credit securities, mortgage-backed securities, and asset back securities assets, are included in commingled trusts or separately managed accounts. The 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, 2024 and 2023. Information related to the Other NQBP is not included in the following tables (in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2024	2023	2024	2023	2024	2023
Benefit obligation:						
As of January 1	$ 690	$ 695	$ 35	$ 43	$ 18	$ 18
Service cost	10	10	1	1	--	--
Interest cost	33	37	2	2	--	1
Actuarial (gain) loss	(40)	37	1	3	--	2
Benefits paid from plan assets	(78)	(86)	(3)	(2)	(2)	(3)
Benefits paid from Company assets	--	--	--	(1)	--	--
Administrative expenses	(3)	(3)	--	--	--	--
Plan settlements	--	--	--	(11)	--	--
Special/contractual termination benefits	--	--	1	--	--	--
As of December 31	$ 612	$ 690	$ 37	$ 35	$ 16	$ 18
Fair value of plan assets:						
As of January 1	$ 530	$ 547	$ 23	$ 21	$ 17	$ 19
Actual return on plan assets	19	72	2	2	(1)	(2)

Company contributions	16	--	3	13	2	3
Benefit payments	(78)	(86)	(3)	(2)	(2)	(3)
Administrative expenses	(3)	(3)	--	--	--	--
Plan settlements	--	--	--	(11)	--	--
As of December 31	$ 484	$ 530	$ 25	$ 23	$ 16	$ 17
Unfunded position as of December 31	$ (128)	$ (160)	$ (12)	$ (12)	$ --	$ (1)
Accumulated benefit plan obligation as of December 31	$ 574	$ 645	N/A	N/A	$ 16	$ 17
Classification in Comparative Balance Sheet:						
Noncurrent asset	$ --	$ --	$ --	$ --	$ 16	$ 17
Current liability	--	--	(1)	--	(2)	(2)
Noncurrent liability	(128)	(160)	(11)	(12)	(14)	(16)
Net asset (liability)	$ (128)	$ (160)	$ (12)	$ (12)	$ --	$ (1)
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ (20)	$ 8	$ --	$ 2	$ --	$ 2
Net settlement gain (loss)	--	--	--	1	--	--
Amortization of net actuarial gain (loss)	--	--	--	1	(1)	(1)
Amortization of prior service credit	--	1	--	--	--	--
	$ (20)	$ 9	$ --	$ 4	$ (1)	$ 1
Amounts included in AOCL: *						
Net actuarial loss (gain)	$ 85	$ 105	$ (3)	$ (3)	$ 6	$ 7
Prior service cost	(1)	(1)	--	--	--	--
	$ 84	$ 104	$ (3)	$ (3)	$ 6	$ 7

* 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 a gain of $40 million and a loss of $37 million, primarily due to changes in the discount rate, and the changes between actual and expected return on plan assets were a loss of $20 million and a gain of $29 million, for the years ended December 31, 2024 and 2023, respectively.
- For the other postretirement benefits, actuarial gains and losses due to demographic experience, including assumption changes, were a loss of $1 million and a loss of $3 million, and the changes between actual and expected return on plan assets were a gain of $1 million and a gain of $1 million, for the years ended December 31, 2024 and 2023, 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	
	2024	2023	2024	2023	2024	2023
Service cost	$ 10	$ 10	$ 1	$ 1	$ --	$ --
Interest cost on benefit obligation	33	37	2	2	--	1

	Defined Benefit Pension Plan 2024	Defined Benefit Pension Plan 2023	Other Postretirement Benefits 2024	Other Postretirement Benefits 2023	Non-Qualified Benefit Plans 2024	Non-Qualified Benefit Plans 2023
Expected return on plan assets	(39)	(43)	(1)	(1)	--	--
Amortization of prior service credit	--	(1)	--	--	--	--
Amortization of net actuarial loss (gain)	--	--	--	(1)	1	1
Settlement gain	--	--	--	(1)	--	--
Net periodic benefit cost	$ 4	$ 3	$ 2	$ --	$ 1	$ 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	
	2024	2023	2024	2023	2024	2023
Assumptions used to determine benefit obligations:						
Discount rate	5.70 %	5.13 %	5.59% - 6.11 %	5.18% - 5.57 %	5.70 %	5.13 %
Rate of compensation increase	4.08 %	4.19 %	4.02 %	4.06 %	3.98 %	4.01 %
Assumptions used to determine net periodic benefit cost:						
Discount rate	5.13 %	5.42 %	5.18% - 5.57 %	5.47% - 6.06 %	5.13 %	5.42 %
Rate of compensation increase	4.19 %	4.21 %	4.06 %	4.04 %	4.01 %	5.10 %
Long-term rate of return on plan assets	6.88 %	6.75 %	4.73 %	4.77 %	N/A	N/A

As of December 31, 2024, there are no liabilities with sensitivity to health care cost trend rates.

The expected rate of return on plan assets each year is based on the approved asset allocation. A forward looking building blocks approach is used with historical returns, capital markets information and survey information used to support the expected rate of return on plan assets assumption.

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					
	2025	2026	2027	2028	2029	2030 - 2034
Defined benefit pension plan	$ 73	$ 45	$ 45	$ 45	$ 45	$ 225
Other postretirement benefits	4	4	4	4	4	11
Non-qualified benefit plans	2	2	2	2	2	8
Total	$ 79	$ 51	$ 51	$ 51	$ 51	$ 244

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 7% of the employee's base pay and also contributes 1% of the employee's base pay, whether or not the employee contributes to the 401(k) Plan as a profit share.

For the majority of bargaining employees who are subject to the International Brotherhood of Electrical Workers Local 125 agreements the Company adds an additional 1% of the employee's base salary to their profit share.

For eligible employees who are not covered by PGE's defined benefit pension plan, the Company matches employee contributions up to 6% of the employee's base pay, and also contributes up to 7% of the employee's base pay as a profit share.

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 $37 million in 2024, $31 million in 2023, and $29 million in 2022.

NOTE 11: INCOME TAXES

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

	Years Ended December 31, 2024	2023
Current:		
Federal	$ 2	$ 11
State and local	12	26
	14	37
Deferred:		
Federal	(2)	4
State and local	25	4
	23	8
Income tax expense	$ 37	$ 45

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, 2024	2023
Federal statutory tax rate	21.0 %	21.0 %
Federal tax credits (1)	(16.9)	(9.5)
State and local taxes, net of federal tax benefit	8.4	8.6
Flow through depreciation and cost basis differences	(0.9)	(0.4)
Reversal of excess deferred income tax (2)	(2.6)	(3.9)
Executive compensation	1.3	0.5
Other	0.4	0.1
Effective tax rate	10.7 %	16.4 %

(1) Federal tax credits consist primarily of 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 2034. Federal tax credits also includes all other federal tax credits and related deferrals. The tax credit deferrals are established to provide the benefit back to customers over a period agreed upon with the OPUC.

(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, 2024	As of December 31, 2023
Deferred Income Tax Assets:		
Employee benefits	$ 89	$ 99
Depreciation and amortization	310	309
Regulatory liabilities	33	21
Tax credits	69	73
Deferred investment tax credits	14	--
Price risk management	60	66
Other	4	2
Total Deferred Income Tax Assets	579	570
Deferred Income Tax Liabilities:		
Depreciation and amortization	949	888
Price risk management	9	9
Regulatory assets	171	146
Other	16	16
Total Deferred Income Tax Liabilities	1,145	1,059
Accumulated Deferred Income Tax Liability, net	$ 566	$ 489

As of December 31, 2024, PGE has federal credit carryforwards of $69 million, consisting of primarily PTCs, which will expire at various dates through 2044. PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2024 and 2023 will be realized; accordingly, no material valuation allowance has been recorded. As of December 31, 2024, and 2023, 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.

NOTE 12: EQUITY-BASED PLANS

At-the-Market Offering Program

In April 2023, PGE entered into an equity distribution agreement under which it could sell up to $300 million of its common stock through at-the-market offering programs. In 2023, pursuant to the terms of the equity distribution agreement, PGE entered into separate forward sale agreements with forward counterparties. In March 2024, the Company issued 1,714,972 shares pursuant to the forward sale agreements and received net proceeds of $78 million. In 2024, PGE entered into additional forward sale agreements with forward counterparties, exhausting the $300 million facility. In the third quarter of 2024, the Company issued 2,351,070 shares pursuant to the additional forward sale agreements and received net proceeds of $100 million. In October 2024, the Company issued 2,788,431 shares pursuant to the additional forward sale agreements, settling the transaction, and received net proceeds of $119 million.

On July 26, 2024, PGE entered into an equity distribution agreement under which it could sell up to $400 million of its common stock through at-the-market offering programs. In the fourth quarter the Company entered into forward sale agreements for 1,420,049 shares. In December 2024, the Company issued 1,066,549 shares pursuant to the forward sale agreements and received net proceeds of $50 million. The Company could have physically settled the remaining amount by delivering 353,500 shares in exchange for cash of $17 million as of December 31, 2024. Any proceeds from the issuances of common stock will be used for general corporate purposes and investments in renewables and non-emitting dispatchable capacity.

Prior to settlement, the potentially issuable shares pursuant to the agreements will be considered in PGE's diluted earnings per share calculations using the treasury stock method. Under this method, the number of shares of PGE's common stock used in calculating diluted earnings per share for a reporting period would be increased by the number of shares, if any, that would be issued upon physical settlement of the agreements less the number of shares that could be purchased by PGE in the market with the proceeds received from issuance (based on the average market price during that reporting period). Share dilution occurs when the average market price of PGE's stock during the reporting period is higher than the average forward sale price during the reporting period. As of the year ended December 31, 2024, no shares were included in the calculation of diluted EPS related to the securities under the agreements. For additional information concerning the Company's diluted earnings per share, see Note 15, Earnings Per Share.

Equity Forward Sale Agreement

In 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. In March 2023, the Company issued 7,178,016 shares pursuant to the EFSA and received net proceeds of $300 million. In June 2023, the Company issued 2,212,610 shares pursuant to the EFSA and received net proceeds of $92 million. In July 2023, the Company issued 2,224,374 shares pursuant to the EFSA, settling the equity forward transaction, and received net proceeds of $92 million.

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 did not receive any proceeds from the sale of common stock until the EFSA was settled (described above), and at that time PGE recorded the proceeds in equity.

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.

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP) under which a total of 1,125,000 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, 2024, there were 563,318 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, 2024, there were 2,454,599 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 April 21, 2023 (the Plan), the Company may grant a variety of equity-based awards, including 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, 2022	579,461	49.23
Granted	421,788	47.82
Forfeited	(57,566)	48.03
Vested	(297,986)	52.45
Nonvested units as of December 31, 2023	645,697	47.57

Granted	478,509	41.02
Forfeited	(20,774)	45.32
Vested	(306,639)	44.76
Nonvested units as of December 31, 2024	796,793	44.78

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 1,257,237 shares remain available for future issuance as of December 31, 2024.

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 stockholders 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 $8 million for the year ended December 31, 2024 and $9 million for 2023.

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 portfolio--and relative total stockholder 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:

	2024	2023
Risk-free interest rate	4.3 %	4.2 %
Expected term (in years)	2.9	2.9
Volatility	12.4 % - 53.2 %	21.8 % - 31.5 %

There is no expected dividend yield used in the valuation, as it is assumed that all dividends distributed during the performance period are reinvested in the Company's underlying stock. The fair value of performance-based RSUs is charged to compensation expense on a straight-line basis over the requisite service period for the entire award based on the number of shares expected to vest. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the weighted average vesting of 105.4% and 149.7% of awarded performance-based RSUs for the respective 2024 and 2023 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $6 million for the year ended December 31, 2024 and $7 million for 2023.

Stock-based compensation, included in Administrative and General Expenses in the Statement of Income, was $24 million for the year ended December 31, 2024 and $17 million for 2023. 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 Stockholders' equity of $4 million in 2024 and in 2023.

As of December 31, 2024, unrecognized stock-based compensation expense was $12 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, 2024, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2025	2026	2027	2028	2029	Thereafter	Total
Capital and other purchase commitments	$ 564	$ 147	$ 82	$ 12	$ 2	$ 40	$ 847
Purchased Power							
Electricity purchases	560	458	347	351	343	3,009	5,068
Capacity contracts	186	218	128	129	130	271	1,062
Public utility districts	11	10	9	7	1	14	52
Natural gas	109	89	45	44	30	177	494
Coal and transportation	27	--	--	--	--	--	27
Total	$ 1,457	$ 922	$ 611	$ 543	$ 506	$ 3,511	$ 7,550

Capital and other purchase commitments--Certain commitments have been made for 2025 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 PPAs 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.

PGE has evaluated its long-term PPAs under variable interest entity accounting guidance. The Company has concluded that it either has no variable interest in the PPAs or, where variable interests exist, PGE is not the primary beneficiary. As a result, consolidation of these entities is not required. This determination is based on PGE lacking both control over significant activities and obligation to absorb losses or receive benefits from the entities' performance. PGE's financial exposure in these PPAs is limited to capacity and energy payments, which are recovered through the AUT and are subject to the PCAM as detailed in Note 2.

Public utility districts--PGE has long-term PPAs 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 one of 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 one of 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, 2024	PGE's Average Share as of December 31, 2024		Contract Expiration	Total PGE Contract Costs	
		Output	Capacity (in MW)		2024	2023
Priest Rapids and Wanapum	$ 1,673	8.6 %	163	2052	$ 75	$ 77
Wells	273	9.0	29	2028	11	11

The agreements for Priest Rapids and Wanapum 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. In connection with the agreement to transfer certain tax credits generated in 2023 and 2024, PGE provided indemnification against the buyer's losses related to a failure to satisfy the PTC and ITC qualification or transferability requirements under the Internal Revenue Code, but not due to the action or legal tax status of the buyer or a change in tax law. As of December 31, 2024, 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, 2024 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 PPAs that rely on identified plant. Variable payments are generally related to gas storage and PPAs 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):

	2024	2023
Operating lease cost	$ 2	$ 4
Finance lease cost:		
Amortization of right-of-use assets	$ 14	$ 14
Interest on lease liabilities	14	15
Total finance lease cost	$ 28	$ 29
Variable lease cost	$ 28	$ 33

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, 2024	2023
Operating Leases:			
Operating lease right-of-use assets	Net Utility Plant	$ 312	$ 18
Current liabilities	Obligations Under Capital Leases - Current	$ 26	$ 3
Noncurrent liabilities	Obligations Under Capital Leases - Noncurrent	286	16
Total operating lease liabilities *		$ 312	$ 19
Finance Leases:			
Finance lease right-of-use assets	Net Utility Plant	$ 276	$ 291
Current liabilities	Obligations Under Capital Leases - Current	$ 27	$ 20
Noncurrent liabilities	Obligations Under Capital Leases - Noncurrent	276	289
Total finance lease liabilities *		$ 303	$ 309

* Included in lease liabilities are $599 million and $311 million related to purchased power and storage contracts for the years ended December 31, 2024 and 2023, respectively. These agreements include hydro and natural gas generation PPA's, gas storage, and battery storage, all of which are included within the Company's AUT and PCAM regulatory mechanisms.

Lease term and discount rates were as follows:

	December 31, 2024	December 31, 2023
Weighted Average Remaining Lease Term (in years)		
Operating leases	22	51
Finance leases	20	21
Weighted Average Discount Rate		
Operating leases	5.8 %	4.1 %
Finance leases	4.8 %	4.8 %

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, 2024, maturities of lease liabilities were as follows (in millions):

	Operating Leases	Finance Leases
2025	$ 26	$ 27
2026	26	27
2027	26	27
2028	26	26
2029	26	26
Thereafter	414	330
Total lease payments	544	463
Less imputed interest	(232)	(160)
Total	$ 312	$ 303

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

	2024	2023
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows used in operating leases	$ 3	$ 4
Operating cash flows used in finance leases	14	15
Financing cash flows used in finance leases	6	6
Right-of-use assets obtained in leasing arrangements:		
Operating leases	$ 295	$ --
Finance leases	--	--

Battery storage agreement--The Company entered into an agreement for battery storage capacity that commenced on December 20, 2024 and is accounted for as an operating lease. This agreement provides the Company the use of the standalone energy storage facility through December 2044. The Company pays a fixed monthly capacity price for rights to use the leased asset. The Company does not operate or maintain the energy storage facility, and has no purchase options or residual value guarantees relating to the leased asset. The Company determined that the lease term does not represent a major part of the remaining economic life of the underlying asset. For standalone energy storage lease assets, the Company has elected to separate the lease and non-lease components from the total fixed contract consideration.

NOTE 16: JOINTLY-OWNED PLANT

As of December 31, 2024, 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 - Generation	20.00 %	1986	$ 507	$ 449	$ 5
Colstrip-Transmission	Various (2)	1986	69	40	--
Pelton/Round Butte	50.01 %	1958 / 1964	221	76	20
Total			$ 797	$ 565	$ 25

(1) Excludes AROs and Accumulated Provision for Depreciation, Amortization, and Depletion.
(2) 14% of the 2,260 MW transmission facilities between the Colstrip switchyard to the Broadview switchyard, near Billings, Montana, and 16% of the 1,930 MW transmission facilities between the Broadview switchyard and the interconnection point with Bonneville Power Administration's transmission system near Townsend, Montana.

Under the respective joint operating agreements for the 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.

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 entirety of Portland Harbor continues 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.

On November 18, 2024, the EPA issued a Special Notice Letter to 60 entities, including PGE, with requirements and deadlines that may ultimately lead to litigation, in relation to Portland Harbor. The EPA has recommended that recipients coordinate their response, which is due within 120 days. Formal negotiations are anticipated to take approximately two years, concluding in fall 2026 and no later than May 2027.

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 would represent 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 estimated liabilities and recover incurred 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.

During 2024, PGE entered into a settlement agreement with the SEC in connection with its investigation. In connection with that settlement, on September 4, 2024, the SEC entered an administrative cease-and-desist order for violations of Sections 13(b)(2)(A) and 13(b)(2)(B) of the Securities Exchange Act of 1934, as amended, and Rule 13a-15(a) thereunder. These violations relate to the sufficiency of the Company's internal accounting controls, books and records and disclosure controls and procedures regarding the accounting for derivatives and regulatory transactions. The settlement did not include any monetary penalties.

The SEC's administrative order recognized numerous remedial measures promptly undertaken by PGE and its cooperation during the investigation. Such remedial measures, which were adopted by the Company in 2020 based on the recommendations of an independent committee of PGE's Board of Directors, included enhancements to the oversight of energy trading and associated risk management reporting, policies and practices.

Management cannot predict whether there will be any further developments related to the CFTC or FERC investigations.

Colstrip-Related Litigation

The Company has a 20% ownership interest in Colstrip, which is located in the state of Montana and operated by one of the co-owners, Talen Montana, LLC (Talen). 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, along with other matters related to Colstrip, are summarized below.

*Arbitration--I*n March 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. The parties have agreed to stay the arbitration proceedings indefinitely as settlement discussions are underway. PGE cannot predict the ultimate outcome of this matter.

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 alleged they had suffered adverse effects from the defendants' coal dust. In August 2021, the claim was amended to add PGE as a defendant. Plaintiffs sought 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 trial date had been rescheduled for June 2, 2025. In March 2025, the Company reached a settlement in principle with the plaintiffs that would not have a material impact to the Company's results of operations, financial condition, or cash flows.

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: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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				(3,964,435)	(808)		(3,965,243)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				[(a)](1,034,721)	0		(1,034,721)		
3	Preceding Quarter/Year to Date Changes in Fair Value							0		
4	Total (lines 2 and 3)				(1,034,721)	0		(1,034,721)	222,805,469	221,770,748
5	Balance of Account 219 at End of Preceding Quarter/Year				(4,999,156)	(808)		(4,999,964)		
6	Balance of Account 219 at Beginning of Current Year				(4,999,156)	(808)		(4,999,964)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				[(b)]1,144,015			1,144,015		
8	Current Quarter/Year to Date Changes in Fair Value				0			0		
9	Total (lines 7 and 8)				1,144,015			1,144,015	316,305,169	317,449,184
10	Balance of Account 219 at End of Current Quarter/Year				(3,855,141)	(808)		(3,855,949)		

FOOTNOTE DATA

(a) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss
Comprised of the net amount of the actuarial valuation of ($1,427,202) of non-qualified benefit plans net of taxes of $392,480.
(b) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss
Comprised of the net amount of the actuarial valuation of $1,585,750 of non-qualified benefit plans net of taxes of ($441,735).

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)	11,348,253,968	11,348,253,968					
4	Property Under Capital Leases	608,973,076	608,973,076					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	3,083,055,895	3,083,055,895					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	15,040,282,939	15,040,282,939					
9	Leased to Others							
10	Held for Future Use	71,642,341	71,642,341					
11	Construction Work in Progress	569,951,129	569,951,129					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	15,681,876,409	15,681,876,409					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	6,196,192,797	6,196,192,797					
15	Net Utility Plant (13 less 14)	9,485,683,612	9,485,683,612					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	5,573,472,066	5,573,472,066					
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	622,720,731	622,720,731					
22	Total in Service (18 thru 21)	6,196,192,797	6,196,192,797					
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)	6,196,192,797	6,196,192,797					

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)	0				0
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)	0				0
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	0				0
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	0				0
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)	0				0

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	192,297,381	2,135,733	0	0	0	194,433,114
4	(303) Miscellaneous Intangible Plant	768,174,478	63,806,172	19,682,625	0	0	812,298,025
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	960,471,859	65,941,905	19,682,625	0	0	1,006,731,139
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	116,300,825	0	50,106	0	0	116,250,719
10	(312) Boiler Plant Equipment	278,426,996	5,688,113	2,691,217	0	0	281,423,892
11	(313) Engines and Engine-Driven Generators						0
12	(314) Turbogenerator Units	69,558,262	1,705,290	1,686,834	0	0	69,576,718
13	(315) Accessory Electric Equipment	25,071,833	0	0	0	0	25,071,833
14	(316) Misc. Power Plant Equipment	6,666,932	0	17,025	0	0	6,649,907
15	(317) Asset Retirement Costs for Steam Production	34,911,263	(5,923,210)	0	0	0	28,988,053
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	534,264,973	1,470,193	4,445,182	0	0	531,289,984
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	4,811,041	0	0	0	0	4,811,041
28	(331) Structures and Improvements	144,094,551	72,255,582	30,381	0	0	216,319,752
29	(332) Reservoirs, Dams, and Waterways	393,115,879	(22,863,716)	1,784	0	0	370,250,379
30	(333) Water Wheels, Turbines, and Generators	140,992,907	(31,152,627)	363,138	0	0	109,477,142
31	(334) Accessory Electric Equipment	52,538,315	6,890,544	720,456	0	0	58,708,403
32	(335) Misc. Power Plant Equipment	162,387,696	3,329,272	0	(8,636,055)	0	[a]157,080,913
33	(336) Roads, Railroads, and Bridges	16,533,598	486,951	18,886	0	0	17,001,663
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)	914,479,115	28,946,006	1,134,645	(8,636,055)	0	933,654,421

36	D. Other Production Plant						
37	(340) Land and Land Rights	15,047,962	0	0	(1,757,144)	0	[b]13,290,818
38	(341) Structures and Improvements	287,738,739	90,524,636	9,106	0	412,648	378,666,917
39	(342) Fuel Holders, Products, and Accessories	272,913,609	100,887	10,310	(5,052,466)	0	[c]267,951,720
40	(343) Prime Movers						0
41	(344) Generators	2,630,436,346	323,665,804	6,606,933	0	163,963	2,947,659,180
42	(345) Accessory Electric Equipment	154,251,714	98,905,636	778	0	(533,128)	252,623,444
43	(346) Misc. Power Plant Equipment	47,379,574	21,450,064	17,941	0	(89,504)	68,722,193
44	(347) Asset Retirement Costs for Other Production	28,519,590	1,919,996	0	0	0	30,439,586
44.1	(348) Energy Storage Equipment - Production	32,833,634	0	0	(1,452,130)	0	[d]31,381,504
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,469,121,168	536,567,023	6,645,068	(8,261,740)	(46,021)	3,990,735,362
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,917,865,256	566,983,222	12,224,895	(16,897,795)	(46,021)	5,455,679,767
47	3. Transmission Plant						
48	(350) Land and Land Rights	18,266,721	12,273,847	0	0	0	30,540,568
48.1	(351) Energy Storage Equipment - Transmission						0
49	(352) Structures and Improvements	33,915,106	1,265,498	9,166	0	1,219,189	36,390,627
50	(353) Station Equipment	624,980,333	139,791,864	1,753,919	0	1,811,816	764,830,094
51	(354) Towers and Fixtures	53,259,585	5,541	0	0	0	53,265,126
52	(355) Poles and Fixtures	176,595,167	30,105,157	210,684	0	0	206,489,640
53	(356) Overhead Conductors and Devices	233,816,148	74,545,469	839	0	0	308,360,778
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)	1,141,153,501	257,987,376	1,974,608	0	3,031,005	1,400,197,274
59	4. Distribution Plant						
60	(360) Land and Land Rights	19,982,002	(540,354)	0	0	3,600,000	23,041,648
61	(361) Structures and Improvements	72,541,437	22,984,944	42,183	0	(1,219,189)	94,265,009
62	(362) Station Equipment	817,727,804	63,496,378	4,128,463	0	(1,805,892)	875,289,827
63	(363) Energy Storage Equipment – Distribution	3,235,751	184,162,485	384,933	295,342,292	(14,182)	[e]482,341,413
64	(364) Poles, Towers, and Fixtures	736,160,549	127,229,534	2,821,662	0	8,258	860,576,679
65	(365) Overhead Conductors and Devices	900,015,873	62,308,422	1,169,284	0	0	961,155,011
66	(366) Underground Conduit	32,555,365	48,009,983	0	0	0	80,565,348
67	(367) Underground Conductors and Devices	1,062,744,207	62,537,537	91,920	0	0	1,125,189,824
68	(368) Line Transformers	567,506,456	11,049,188	487,723	0	0	578,067,921
69	(369) Services	595,901,071	49,910,721	0	0	0	645,811,792
70	(370) Meters	233,667,462	2,912,635	13,014	0	0	236,567,083
71	(371) Installations on Customer Premises	10,025,113	3,708,840	0	0	0	13,733,953
72	(372) Leased Property on Customer Premises						0
73	(373) Street Lighting and Signal Systems	197,947,491	16,639,049	0	0	0	214,586,540
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)	5,250,487,313	654,409,362	9,139,182	295,342,292	568,995	6,191,668,780
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	23,487,410	663,547	0	0	0	24,150,957
87	(390) Structures and Improvements	335,809,477	14,059,621	1,577,273	(589,746)	0	(f)347,702,079
88	(391) Office Furniture and Equipment	120,305,512	16,908,481	23,463,820	0	0	113,750,173
89	(392) Transportation Equipment	104,236,061	13,427,965	2,536,513	0	19,778	115,147,291
90	(393) Stores Equipment	4,149,651	0	67,576	0	0	4,082,075
91	(394) Tools, Shop and Garage Equipment	25,692,431	3,051,297	495,275	0	0	28,248,453
92	(395) Laboratory Equipment	12,579,319	0	973,827	0	0	11,605,492
93	(396) Power Operated Equipment	44,538,938	0	2,738,407	0	(19,778)	41,780,753
94	(397) Communication Equipment	302,133,982	40,458,505	46,909,648	0	46,021	295,728,860
95	(398) Miscellaneous Equipment	3,739,950	5,022	415	0	0	3,744,557
96	SUBTOTAL (Enter Total of lines 86 thru 95)	976,672,731	88,574,438	78,762,754	(589,746)	46,021	985,940,690
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)	976,738,020	88,574,438	78,762,754	(589,746)	46,021	986,005,979
100	TOTAL (Accounts 101 and 106)	13,246,715,949	1,633,896,303	121,784,064	277,854,751	3,600,000	15,040,282,939
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)	13,246,715,949	1,633,896,303	121,784,064	277,854,751	3,600,000	15,040,282,939

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: MiscellaneousPowerPlantEquipmentHydraulicProduction

Includes activities of capitalized lease assets.

(b) Concept: LandAndLandRightsOtherProduction

Includes activities of capitalized lease assets.

(c) Concept: FuelHoldersProducersAndAccessoriesOtherProduction

Includes activities of capitalized lease assets.

(d) Concept: EnergyStorageEquipmentOtherProduction

Includes activities of capitalized lease assets.

(e) Concept: EnergyStorageEquipmentDistributionPlant

Includes activities of capitalized lease assets.

(f) Concept: StructuresAndImprovements

Includes activities of capitalized lease assets.

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
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46							
47	TOTAL						

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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)	(m)	543,591
3	Sewell, Washington County, OR	(b)	(n)	2,817,507
4	Sewell Easement, Washington County, OR	(c)	(o)	332,379
5	Boardman, Morrow County, OR	(d)	(p)	832,853
6	Woodburn, Marion County, OR	(e)	(q)	20,290,058
7	Sunset, Washington County, OR	(f)	(r)	5,895,936
8	Berger/Majestic, Washington County, OR	(g)	(s)	13,403,236
9	Ahmad, Multnomah County, OR	(h)	(t)	1,959,257
10	Glee/Madden West and East, Multnomah County, OR	(i)	(u)	5,786,788
11	Harrington, Multnomah County, OR	(j)	(v)	5,096,284
12	Kerr, Multnomah County, OR	(k)	(w)	14,363,265
13	Other Land and Land Rights	(l)	(x)	321,187
21	Other Property:			
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47	TOTAL			71,642,341

FOOTNOTE DATA

(a) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2007

(b) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2008

(c) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2009

(d) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2020

(e) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2022

(f) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2022

(g) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2023

(h) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2024

(i) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2024

(j) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2024

(k) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

2024

(l) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseOriginalDate

Various

(m) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(n) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(o) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(p) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(q) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(r) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(s) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(t) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(u) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(v) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(w) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

(x) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

Future

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	Seaside Battery Energy Storage	224,537,456
2	Reedville Substation Rebuild	29,731,483
3	Memorial Substation Build	27,460,796
4	Tonquin Substation Build	24,335,210
5	Round Butte Replace Turbine Shutoff Valves	[(a)]15,078,294
6	Monitor Sub Rebuild (WVRP)	10,357,249
7	Maximo Application Suite Upgrade	9,952,886
8	South Milliken 57kV Line Rebuild	9,580,837
9	Harrison 11kV to 13kV Conversion	7,811,506
10	Install Diesel Particulate Filters	7,457,628
11	T&D Spares and LLT Capital Assets	7,397,461
12	Western Resource Adequacy Program	6,947,301
13	Marquam Capacity Addition - Terwilliger	6,598,596
14	Beaver Modernization	5,299,628
15	Oregon City Line Center Project	5,247,418
16	Extended Day-Ahead Market (EDAM)	5,135,738
17	Facilities Upgrades-EV Readiness	5,014,986
18	Redland Substation Upgrades	4,972,875
19	Harborton Reliability Project	8,510,020
20	Build Evergreen Substation Phase 3	4,893,207
21	Glisan Substation Transformer Upgrade	4,882,611
22	Asset and Resource Management Tool (ARM)	4,745,635
23	Boeckman Road Widening	4,240,729
24	Colstrip Coal Capital Project	[(b)]4,185,568
25	Hydro Control System Upgrade	4,091,386
26	PPMS Project Portfolio Management System	4,009,148
27	Blue Lake Distribution Feeders	3,807,743
28	Pearl-Sherwood Upgrades	3,741,544
29	BPA Substation Upgrades	3,643,523
30	Substation Equipment Replacement	3,635,627
31	Waconda Substation Expand	3,528,380
32	Clackamas River Hydro Recreation, Aesthetic & Cultural Project	3,509,412
33	Salem Smart Power Center Repower	3,264,393
34	Replace or Rewind Failed Transformers	3,112,949
35	Project 360-Phase 2	2,909,735
36	Enterprise DERMS & DER System of Record	2,698,035
37	PGE / DTNA Heavy Duty Charging Station	2,633,045
38	Beaver Economizer Upgrade	2,588,207
39	St. Louis Substation Rebuild	2,357,297
40	Substation Communication Upgrade	2,337,081

41	Build Evergreen Phase 4	2,276,227
42	Replace/Rewind Failed Transformers	2,164,289
43	As-Built Drawings - Generation II	2,070,234
44	Enterprise SIEM replacement	1,956,909
45	Outage Management System Upgrade	1,866,943
46	Expeto Wireless Platform & Service	1,708,601
47	Biglow Canyon Upgrade Wind SCADA systems	1,681,341
48	Wheatridge Demonstration Project	1,523,378
49	Hydro Structural/Reliability Upgrades	1,495,507
50	Pelton Round Butte Construct Fish Facilities	(c)1,465,966
51	Integrated Distribution Planning Tools	1,444,973
52	Wildfire Mitigation Leland-Carus	1,325,538
53	Wildfire Mitigation - UG Willamina	1,230,273
54	EV Fleet Partner Phase 2	1,206,994
55	Beaver Rewind U4 Generator Rotor	1,194,952
56	Wildfire Mitigation -UG Grand Ronde	1,191,182
57	Grid Edge Computing	1,173,205
58	PW2: 2024-2025 Valve Replacements	1,073,787
59	Workplace Strategy & Design Fitness	1,070,219
60	Pelton Round Butte Mitigation Enhancement Fund	(d)1,062,713
61	Transmission and Distribution Asset Relocation	1,050,071
62	Faraday Dam Diversion	973,535
63	Generation Facility Fitness	958,596
64	Hydro Emergency Generators	939,999
65	Beaver Blade Replacement	909,334
66	Substation Upgrades	899,688
67	Waconda Fiber Upgrades	888,196
68	Clackamas Road Improvements	873,610
69	Faraday Seepage Collection	868,104
70	Wind Generation Fitness	853,108
71	Oil Circuit Breaker Replacement	830,069
72	Coyote Springs Unit 1 Remedial Action Scheme	827,227
73	Beaver Generator Breaker Replacement	811,568
74	Marquam Capacity Addition - Sam Jackson	770,920
75	Tech Landscape 2024-2025	700,716
76	Minor Projects, <$1 million, represents 5% of the Total CWIP Balance	30,370,534
43	Total	569,951,129

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

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	5,288,576,622	5,288,576,622	0	0
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	392,816,166	392,816,166		
4	(403.1) Depreciation Expense for Asset Retirement Costs	13,420,449	13,420,449		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	7,866,167	7,866,167		
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)	414,102,782	414,102,782	0	0
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(102,101,438)	(102,101,438)		
13	Cost of Removal	(29,343,423)	(29,343,423)		
14	Salvage (Credit)	2,237,523	2,237,523		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(129,207,338)	(129,207,338)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1					
17.2					
17.3					
17.4					
17.5					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	5,573,472,066	5,573,472,066	0	0
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	502,037,800	502,037,800		
21	Nuclear Production				
22	Hydraulic Production-Conventional	327,781,108	327,781,108		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,334,668,237	1,334,668,237		
25	Transmission	453,937,091	453,937,091		
26	Distribution	2,645,842,149	2,645,842,149		
27	Regional Transmission and Market Operation				
28	General	309,205,681	309,205,681		

29	TOTAL (Enter Total of lines 20 thru 28)	5,573,472,066	5,573,472,066	0	0

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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			8,382,400	1,278,305		9,660,705	
4	Paid in Capital			77,528,661			77,528,661	
5	SubTotal			85,912,061	1,278,305	0	87,190,366	0
6	Slamon 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	84,967,379	1,278,305	0	86,245,684	0

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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)	28,001,414	21,338,923	Generation
2	Fuel Stock Expenses Undistributed (Account 152)	0	0	
3	Residuals and Extracted Products (Account 153)	0	0	
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	42,274,899	41,616,304	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	19,252,448	20,353,137	Generation
8	Transmission Plant (Estimated)	743,018	564,960	Transmission
9	Distribution Plant (Estimated)	15,861,078	23,657,898	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[a]704,966	[b]1,722,087	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	78,836,409	87,914,386	
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)	3,950,888	4,343,197	
17				
18				
19				
20	TOTAL Materials and Supplies	110,788,711	113,596,506	

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).

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	107,490		10,029		10,031		10,030		60,457		198,037	
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	64										64	
19	Other:												
20	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	107,426		10,029		10,031		10,030		61,778		199,294	0
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	1,395		193		193		193		1,691		3,665	
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales	193								193		386	
40	Balance-End of Year	1,202		193		193		193		1,498		3,279	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)		4								4		8
45	Gains												
46	Losses												

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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: 04/11/2025	Year/Period of Report End of: 2024/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					0

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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 expenses in rates until decommissioning is complete, as authorized by OPUC (Order No. 07-015, dtd 1/12/2007)	503,929,778	23,981,349	407	[a](1,900,000)	160,790,054
49	TOTAL	503,929,778	23,981,349		(1,900,000)	160,790,054

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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), offset in Account 407.

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	LLIR 23-113 SIS	723	561.6		
3	LLIR 24-115 APP	242	561.6		
4	LLIR Boardman Affected Systems	463	561.6		
5	Residual Allocation Adjustments from Correction of Miscoded Entries	126	561.6		
20	Total	1,554			
21	**Generation Studies**				
22	LGIP 21-095 APP	12,098	561.7		
23	LGIP 21-095 FEA	(21,928)	561.7		
24	LGIP 21-102 Bluebird	166	561.7		
25	LGIP 21-103 Waxwing	121	561.7		
26	LGIP 21-099 FEA	1,043	561.7		
27	LGIP 21-101 FEA	3	561.7		
28	LGIP 21-102 FEA	3	561.7		
29	LGIP 21-103 FEA	679	561.7		
30	LGIP 21-095 SIS	58,244	561.7		
31	LGIP 22-107 FEA	115	561.7		
32	Cascade Renewable LLIR - FEA	122	561.7		
33	LGIP 21-104 FEA	11	561.7		
34	LGIP 21-105 FEA	919	561.7		
35	LGIP 22-109 FEA	963	561.7		
36	LGIP 22-110 FEA	22,333	561.7		
37	LGIP 22-108 FEA	230	561.7		
38	LLIR SIS - PAC Dalreed	17,127	561.7		
39	LGIP System Impact Study	14	561.7		
40	LGIP 21-099 SIS	115	561.7		
41	LGIP 21-096 FAC	347	561.7		
42	LGIP 22-117 APP	3	561.7		
43	LGIP 22-111 FEA	22,958	561.7		
44	LGIP 22-100 SIS	493	561.7		
45	LGIP 22-114 FEA	28,531	561.7		
46	LGIP 22- 113 FEA	29,739	561.7		
47	LGIP 22-115 FEA	23,414	561.7		
48	LGIP 21-101 SIS	558	561.7		
49	LLIR 22-003 SIS	1,496	561.7		
50	21-22 TSEP Affected System Study	220,885	561.7		
51	LGIP 21-102 SIS	44,609	561.7		

52	LLIR 23-004		115	561.7		
53	Feasibility Study Deposits		8,471	561.7		
54	LGIP 17-067 Provisional Request		1,163	561.7		
55	LGIP 21-099 FAC		7,207	561.7		
56	LGIP 21-100 FAC		7,907	561.7		
57	LGIP 21-101 FAC		6,343	561.7		
58	LGIP 21-102 FAC		2,881	561.7		
59	LGIP 21-103 FAC		3,831	561.7		
60	LGIP 21-103 SIS		42,000	561.7		
61	LGIP 21-105 SIS		87,787	561.7		
62	LGIP 22-109 SIS		193	561.7		
63	LGIP 23-237 APP		11,034	561.7		
64	LGIP 23-239 APP		85	561.7		
65	LGIP 24-240 App		360	561.7		
66	LGIP 24-241 App		642	561.7		
67	LGIP 24-242 APP		383	561.7		
68	LGIP 24-243 APP		296	561.7		
69	LGIP 24-244 APP		325	561.7		
70	LGIP 24-245 App		120	561.7		
71	LGIP 24-248 APP		297	561.7		
72	LGIP 24-249 App		391	561.7		
73	LGIP 24-250 APP		117	561.7		
74	LGIP 24-258 APP		105	561.7		
75	LGIP SALM Surplus		42,517	561.7		
76	LLIR 22-003 Study		3,657	561.7		
77	LLIR 22-006 Study		26,092	561.7		
78	LLIR 22-007 Study		26,000	561.7		
79	LLIR 22-008 Study		26,000	561.7		
80	LLIR 23-113 FEA		23,370	561.7		
81	LLIR 23-113 SIS		459	561.7		
82	LLIR 24-115 APP		373	561.7		
83	LLIR Boardman Affected Systems		36,555	561.7		
84	LLIR Warm Springs Affected Systems		91	561.7		
85	PAC Dual Mesa LLIR Affected Systems		92	561.7		
86	SALM Surplus IC FAC Study		290	561.7		
87	SGIP Study		271	561.7		
88	SPQ0274 FAC		98	561.7		
89	SPQ0280 FAC		147	561.7		
90	Residual Allocation Adjustments from Correction of Miscoded Entries		(101)	561.7		
39	Total		833,375			
40	Grand Total		834,929			

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Tax Benefits Related to Book/Tax Basis Differences (Amort. period is based on the lives of the properties, approximately 25 years.)	40,816,521	148,772,579	282	144,488,913	45,100,187
2	Previously Flowed to Customers (Amort. period is based on the lives of the properties, approximately 25 years.)	15,482,127	52,839,305	283	54,806,134	13,515,298
3	Price Risk Management	206,136,656	730,799,637	182.3 / 547 / 555	752,293,841	184,642,452
4	Deferred Broker Settlement	1	66,050,157	254 / 547 / 555	52,128,585	13,921,573
5	Intervenor Funding - SB 978 (original deferral per OPUC Order No. 03-388 dtd 7/2/2003).	715	9	407.3	594	130
6	Intervenor Funding - CUB (original deferral per OPUC Order No. 03-388 dtd 7/2/2003).	203,043	10,085	407.3	21,806	191,322
7	Intervenor Funding - Match (original deferral per OPUC Order No. 03-388 dtd 7/2/2003).	142,705	318,724	407.3	17,939	443,490
8	Intervenor Funding - Issue (original deferral per OPUC Order No. 03-388 dtd 7/2/2003).	373,524	156,491	407.3	32,594	497,421
9	Intervenor Funding - JFA (original deferral per OPUC Order No. 23-033 dtd 2/8/2023)	179,669	98,252		0	277,921
10	Residual Deferred Account (per OPUC Order No. 10-279 dtd 7/23/2010)	5	(5,147)		0	(5,142)
11	Glass Insulator Deferral (per OPUC Order No. 10-478 dtd 12/17/2010; UE 215 First Revenue Requirement Stipulation) Amortization period: 56 years	5,079,897	0	571	106,333	4,973,564
12	Pension Funding Postretirement Funding (Per SFAS No. 158 adopted 12/31/2006; OPUC Order No. 07-051 dtd 2/12/2007)	103,502,635	240,380	219	19,624,818	84,118,197
13	Automated Demand Response Cost Recovery Mechanism (Per OPUC Advice No. 17-29, dtd 11/13/17), Amortizing through 12/31/2024.	0	7,151,858	143 / 182.3 / 232 / 254 / 407.3 / 431	7,151,859	(1)
14	Demand Response Testbed (Per OPUC Order No. 19-425, dtd 12/06/2019), Amortizing through 12/31/2024.	149,769	986,020	182.3 / 232 / 254	1,135,789	0
15	Deferred Cost - FLEX Pricing Program (Per OPUC Order No. 19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2024.	2,100	2,616,751	131 / 182.3 / 232 / 254 / 407.3 / 431	2,616,751	2,100
16	Deferred Cost - DLC Thermostat (Per OPUC Order No.19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2024.	0	4,879,548	182.3 / 232 / 254 / 407.3 / 431	4,879,548	0
17	Gresham Privilege Tax Collection Deferral (Advice No. 17-05, Schedule 134, dtd 02/24/17).	0	5	407.3	2	3
18	Portland Harbor Environmental Remediation Deferral (Per OPUC Order No. 17-071, Docket No. UM1789, dtd 03/02/17)	35,177,280	3,463,319	143 / 923 / 421	1,553,686	37,086,913
19	Debt Issuance (Interest Rate Hedges for Long Term Debt Amortization period: 30 years beginning April 2019)	3,958,743	0	428.1	156,264	3,802,479
20	Transportation Electrification Prgm (UM 1938).	1,932	448,015	143 / 182.3 / 232 / 253 / 254 / 431 / 908 / 935	449,946	1
21	EV Charging (Per UM 2003, Order No. 20-381, dtd 10/27/2020), Amortizing through 12/31/2024.	0	2,020,446	182.3 / 232 / 254 / 431 / 908	2,020,446	0
22	HB-2165 (UM 2218), Amortizing through 12/31/2024.	0	8,918	182.3 / 254	8,918	0
23	Income Qualified Bill Discounts (UM 2219), Amortizing through 12/31/2024.	(67,742)	44,544,949	431 / 903	44,477,206	1
24	Multifamily Water Heater (Per Advice Filing No. 17-06, UM-1827, Order No. 17-224, dtd 6/27/2017), Amortizing through 12/31/2024.	0	918,717	182.3 / 254 / 232 / 407.3 / 431	918,717	0
25	Community Solar (Per UM-1977, OPUC Order No. 18-477, dtd 12/19/2018), Amortizing through 12/31/2024.	1,115,391	3,521,991	232 / 407.3 / 555	4,184,496	452,886
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 12/31/2024.	105,730	6,582,763	143 / 182.3 / 232 / 254	6,150,569	537,924
27	Residential Battery Energy Storage Pilot (Per UM-2078, Order No. 20-208, dtd 7/6/2020.	7,559	663,008	182.3 / 232 / 254 / 431 / 908	452,437	218,130

28	Wheatridge Renewable Energy Farm (Per UE-370, Order No. 20-279, dtd 8/26/2020), Amortizing through 12/31/2024.	1,424,810	0	553	52,936	1,371,874
29	Labor Day Wildfire - Emergency Widlfie Deferral (Per UM-2115, Order No. 20-389, dtd 10/27/2020), Amortizing through 12/31/2029.	28,527,496	2,349,983	407.3 / 571 / 593	6,526,749	24,350,730
30	COVID-19 (Per UM-2064, Order No. 20-376, dtd 10/27/2020), Amortization period 4/1/2023-3/31/2025.	13,698,953	3,051,184	904	16,159,138	590,999
31	OPUC Fee Deferral (Per UM-2046, Order No. 20-411, dtd 11/05/2020), Amortizing through 12/31/2024.	1,513,252	647,961	407.3	1,565,327	595,886
32	February 2021 Ice Storm - Emergency Restoration Costs (Per UM 2156, filing dtd 2/15/2021), Amortizing through 12/31/2029.	68,601,264	5,643,799	407.3 / 593	15,433,927	58,811,136
33	Decoupling Deferral - 2021 (UM 1417)	315,767	308,182	421 / 456	623,949	0
34	Microgrid Storage (UM 2113, Order No. 20-370).	106,167	834,873	232 / 254 / 407.3 / 421 / 935	941,040	0
35	Independent Evaluator (UM-2184)	621,591	533,113	232	1,980	1,152,724
36	PCAM 2021 (UE-395), Amortizing through 12/31/2024.	15,693,625	3,364,429	555	18,153,643	904,411
37	Wildfire Mitigation Plan (UM-2019), Amortizing through 12/31/2024.	30,218,150	66,008,156	107 / 143 / 232 / 571 / 593	51,942,100	44,284,206
38	Decoupling Deferral - 2022 (UM 1417, Amortization period 1/1/2024-12/31/2024)	5,827,654	206,936	242 / 456	5,856,127	178,463
39	Direct Access 2022 (UM 1301).	75,071	329	254 / 447	75,402	(2)
40	Lease Obligation Balancing Account	24,302,310	12,855,400	547	909	37,156,801
41	Colstrip Decommissioning Deferral (UE-394, 5/09/2022), Amortizing through 12/31/2024.	79,317	130,157	456	68,764	140,710
42	Level III Storm (UE-394), Amortizing through 12/31/2024.	3,525,000	109,525	182.3 / 229 / 593	3,634,524	1
43	CBIAG Deferral (UM 2249) Advice No. 22-36. Amortizing through 12/31/2024.	41,331	289,834	232 / 254	331,165	0
44	Carty Major Maintenance Deferral (Per OPUC Order 15-356 UE-294 dtd 11/3/15)	2,157,953	6,012,091	182.3 / 553	7,170,644	999,400
45	Trojan Decommissioning Deferral (Per OPUC UE-319, Order No.17-511, dtd 12/18/2017), Amortizing through 6/30/2023.	208,882	0		0	208,882
46	Monet NVPC QF Deferral 2023 (UM 1988)	648,000	0		0	648,000
47	Gain on Asset Sales (Per OPUC Order No. 01-777 dtd 8/31/2001), Amortizing through 12/31/2023.	2,503,891	6,007,711	283 / 410.1	294,137	8,217,465
48	Time of Day (TOD) - Deferral 2023 (Per Advice No. 23-40, Special Condition No. 6)	818,426	24,932	449.1	774,222	69,136
49	Time of Day (TOD) - Deferral 2024 (Per Advice No. 23-40, Special Condition No. 6)	304,880	4,476,124		0	4,781,004
50	RCE Deferral (Per OPUC Order 23-386 UE-416)	0	92,159,142		0	92,159,142
51	January 2024 Ice Storm (Per Advice No. 21-309, UM 2190)	0	157,784,222	407.4 / 421 / 593	110,806,697	46,977,525
52	Direct Access 2024 (Per UM 1301)	0	762,528		0	762,528
53	NEEA Funding (Per UM 2234)	0	367,693		0	367,693
54	RVM Deferral (Per OPUC Order 23-386 UE-416)	0	1,769,272	593	1,765,821	3,451
55	Port Westward 1 Major Maint Deferral (Per OPUC UE 262, Order No. 13-459, dtd 12/9/2013)	0	9,067,859	182.3 / 456 / 553	6,623,117	2,444,742
56	Boardman ARO	0	0	254	940,402	(940,402)
57	Asset Retirement Obligations: Balancing Account	0	8,317,558			8,317,558
44	TOTAL	613,582,050	1,460,169,773		1,349,420,911	724,330,912

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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 Credits Account Charged (d)	CREDITS Credits Amount (e)	Balance at End of Year (f)
1	Misc. Undistributed Charges	486,091	907,483	Various	1,359,964	33,610
2	Net Co-owner / Trust Contribution	(399,603)	30,370,816	Various	29,225,696	745,517
3	Deferred Revolving Credit Agreement Fees (amort through Sept 2028)	2,844,953	1,134,000	431	1,164,341	2,814,612
4	Dispatchable Generation (various amort periods from 2013 and extending through 2032)	4,544,786	0	903	1,246,193	3,298,593
5	Utility Property Sales - Selling Expenses	(9,076)	272,680	Various	272,680	(9,076)
47	Miscellaneous Work in Progress	1,035,318				2,847,428
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	8,502,469				9,730,684

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	300,657,360	303,496,910
3	Regulatory Liabilities	22,827,800	31,278,373
4	Employee Benefits	99,302,381	89,227,549
5	Price Risk Management	66,106,884	60,324,453
6	Tax Credits & NOL's	74,160,732	71,777,637
7	Deferred investment tax credits		22,890,562
7	Other	2,854,701	[(a)]4,857,424
8	TOTAL Electric (Enter Total of lines 2 thru 7)	565,909,858	583,852,908
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	7,643,304	[(b)]6,532,727
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	573,553,162	590,385,635

Notes

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Line 7 - Other	2023	2024
Bad Debt Expense	2,614,744	3,253,844
Deferred Revenue	1,107,505	1,101,601
Nuclear Decommissioning Trust	10,090,950	10,415,939
Renewable Energy Development	(2,264,977)	(3,595,729)
Finance Lease Liability	(10,173,570)	(9,507,764)
Miscellaneous	1,480,049	3,189,533
Total - Line 7 - Other	**2,854,701**	**4,857,424**

(b) Concept: AccumulatedDeferredIncomeTaxes

Line 17 - Other Non-Utility	2023	2024
Property Related	7,732,285	6,782,859
Employee Benefits	(88,980)	(250,133)
Total - Line 17 - Other Non-Utility	**7,643,304**	**6,532,727**

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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			109,342,251	2,122,277,163				
7	Total	160,000,000			109,342,251	2,122,277,163				
8	Preferred Stock (Account 204)									
9	Preferred Stock	30,000,000								
12	Total	30,000,000				0				

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-04-11	Year/Period of Report End of: 2024/ 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.

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
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.
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.
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	
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	**Other Paid in Capital**	
18	Beginning Balance Amount	0
19	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	0
40	Total	18,789,718

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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: 04/11/2025	Year/Period of Report End of: 2024/ 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	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	3,437,508
3	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	6,259,992
4	6.31% SERIES DUE 5-1-2036	221	175,000,000		1,270,565	0	0	05/26/2006	05/01/2036	05/26/2006	05/01/2036	175,000,000	11,042,508
5	5.80% SERIES DUE 6-1-2039	221	170,000,000		1,460,968	0	0	05/16/2007	06/01/2039	05/16/2007	06/01/2039	170,000,000	9,859,992
6	5.81% SERIES DUE 10-1-2037	221	130,000,000		1,109,574	0	517,518	09/19/2007	10/01/2037	09/19/2007	10/01/2037	130,000,000	7,553,017
7	$150mm 5.43% SERIES DUE 5-3-2040	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	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	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	$50mm 4.84% SERIES DUE 12/15/2048	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
11	$105mm 4.74% SERIES DUE 11/15/2042	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
12	$100mm 4.39% SERIES DUE 8-15-2045	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
13	$100mm 4.44% SERIES DUE 10-15-2046	221	100,000,000		625,030	0	0	10/15/2014	10/15/2046	10/15/2014	10/15/2046	100,000,000	4,422,520
14	$75mm 3.55% SERIES DUE 1/15/2030	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	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	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	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	$75mm 4.47 Series Due 12/11/2048	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
19	$200mm 4.3% Series Due 4-11- 2049	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
20	$110mm 3.34%% Series Due 10-15-2049	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
21	$160mm 3.34% Series Due 1-15-2050	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
22	$200mm 3.15% Series Due 4-1-2030	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
23	$160mm 1.84% Series Due 12-10-2027	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
24	$70mm 2.32% Series Due 12-10-2032	221	70,000,000		278,000	0	0	12/10/2020	12/10/2032	12/10/2020	12/10/2032	70,000,000	1,624,000
25	$100mm 1.82% Series Due 9-30-2028	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
26	$50mm 2.10% Series Due 9-30-2031	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
27	$100mm 2.20% Series Due 1-15-2034	221	100,000,000		452,981	0	0	09/30/2021	01/15/2034	09/30/2021	01/15/2034	100,000,000	2,200,000
28	$150mm 2.97% Series Due 9-30-2051	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
29	$100mm 5.47% Series Due 11-30-2029	221	100,000,000		438,003	0	0	11/30/2022	11/30/2029	11/30/2022	11/30/2029	100,000,000	5,560,000
30	$100mm 5.56% Series Due 11-30-2033 comm auth 22-031 2/10/2022	221	100,000,000		477,010	0	0	01/13/2023	01/13/2033	01/13/2023	01/13/2033	100,000,000	5,470,000
31	$50m 5.44% Series Due 09-15-2030 comm auth 22-031 2/10/2022	221	50,000,000		202,658	0	0	08/29/2023	09/15/2030	08/29/2023	09/15/2030	50,000,000	2,720,000

32	$150m 5.48% Series Due 9-15-2033 comm auth 22-031 2/10/2022	221	150,000,000		607,974	0	0	08/29/2023	09/15/2033	08/29/2023	09/15/2033	150,000,000	8,220,000
33	$100m 5.68% Series Due 9-15-2038 comm auth 22-031 2/10/2022	221	100,000,000		405,316	0	0	09/14/2023	09/15/2038	09/14/2023	09/15/2038	100,000,000	5,680,000
34	$100m 5.78% Series Due 11-15-2053 comm auth 22-031 2/10/2022	221	100,000,000		145,316	0	0	11/15/2023	11/15/2053	11/15/2023	11/15/2053	100,000,000	5,780,000
35	$100m 5.83% Series Due 11-15-2059 comm auth 22-031 2/10/2022	221	100,000,000		145,316	0	0	11/15/2023	11/15/2059	11/15/2023	11/15/2059	100,000,000	5,830,000
36	$100m 5.15% Series Due 2-22-2029 comm auth 23-450 11/28/2023	221	100,000,000		398,139	0	0	02/22/2024	02/22/2029	02/22/2024	02/22/2029	100,000,000	4,420,417
37	$100m 5.36% Series Due 2-22-2034 comm auth 23-450 11/28/2023	221	100,000,000		398,141	0	0	02/22/2024	02/22/2034	02/22/2024	02/22/2034	100,000,000	4,600,667
38	$250m 5.73% Series Due 2-22-2054 comm auth 23-450 11/28/2023	221	250,000,000		995,530	0	0	02/22/2024	02/22/2054	02/22/2024	02/22/2054	250,000,000	12,295,625
39	$97.8mm CITY FORSYTH 2.125% DUE 05-01-2033	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
40	$21.0mm CITY FORSYTH 2.375% DUE 05-01-2033	221	21,000,000		97,594	0	0	03/11/2020	05/01/2033	03/11/2020	05/01/2033	21,000,000	498,751
41	$80mm 3.51% SERIES DUE 11-15-2024	221	0		501,502	0	0	11/17/2014	11/15/2024	11/17/2014	11/15/2024	0	2,449,200
42	Subtotal		4,368,800,000		21,819,132	(1,956,000)	955,018					4,368,800,000	193,598,947
43	Reacquired Bonds (Account 222)												
44													
45													
46													
47	Subtotal											0	
48	Advances from Associated Companies (Account 223)												
49													
50													
51													
52	Subtotal											0	
53	Other Long Term Debt (Account 224)												
54	$300m Term Loan 366 day term variable interest rate comm auth 23-450 11/28/2023	224	220,000,000		69,350	0	0	11/14/2024	11/17/2025	11/14/2024	11/17/2025	170,000,000	1,587,640
55	Subtotal		220,000,000		69,350	0	0					170,000,000	1,587,640
33	TOTAL		4,588,800,000									4,538,800,000	195,186,587

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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)	316,305,169
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion & Amortization	60,102,171
9	Deductions Recorded on Books Not Deducted for Return	
10	Price Risk Management and Mark-to-Market	(21,494,201)
11	Other	[a]23,870,767
14	Income Recorded on Books Not Included in Return	
15	Depreciation, Depletion & Amortization	38,534,766
16	Regulatory Credits	(28,199,767)
17	Regulatory Debits	84,058,568
18	Other	[b]314,841
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	257,368,748
21	State & Local Tax Deduction	11,317,115
22	Other	[c](110,531)
27	Federal Tax Net Income	15,500,166
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @ 21%	3,255,035
30	PTC	(2,889,380)
31	RTA Federal Tax Adjustment	1,222,840
32	Other Items Affecting Tax	8,469
33	Total Federal Income Tax - PGE	1,596,964

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

Line 12 - Deductions Recorded on Books Not Deducted for Return	
Qualified NDT	1,375,732
Meals & Entertainment	686,961
Political Activity	1,603,614
Bad Debts	2,371,797
Fines and Penalties	217,991
Employee Benefits	(16,327,363)
Federal Tax Expense	98,126
Orion Contingent Royalty Payments	5,936
Tax Finance Lease	2,221,163
Unamortized Loss on Reacquired Debt	1,098,994
State & Local Tax Expense	36,731,019
Deferred Revenue	345,173
Wheatridge RECs	(5,280,071)
Miscellaneous	(1,278,305)
Total Other	**23,870,767**

(b) Concept: IncomeRecordedOnBooksNotIncludedInReturn

Line 17 - Income Recorded on Books Not Included in Return	
Key Man Insurance Proceeds	1,865,398
OCI	(1,585,750)
Miscellaneous	35,193
Total Other	**314,841**

(c) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Line 22 - Deductions on Return Not Charged Against Book Income	
Dividend Received Deduction	13,000
Renewable Energy Initiatives	(2,548,800)
Property Tax	2,460,603
Miscellaneous	(35,334)
Total Other	**(110,531)**

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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 No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	FERC Resale/Coord	Federal Tax	Federal	2024	278,709	0	1,253,831	0	0	1,532,540	0	0	0	0	1,253,831
2	Income Tax	Federal Tax	Federal	2024	0	603,772	1,661,462	3,226,384	0	0	2,168,694	5,909,877	0	0	(4,248,415)
3	Foreign Insurance Excise Tax	Federal Tax	Federal	2024	0	0	0	0	0	0	0	248,996	0	0	(248,996)
4	FICA (Employer Share)	Federal Tax	Federal	2024	1,601,323	0	30,787,038	30,736,048	0	1,652,313	0	13,836,365	0	0	16,950,673
5	Unemployment	Federal Tax	Federal	2024	(98,406)	0	140,388	143,193	0	(101,211)	0	61,291	0	0	79,097
6	Power License	Federal Tax	Federal	2024	366,923	(24,314)	4,317,803	6,081,524	0	(1,412,794)	(40,310)	0	0	0	4,317,803
7	**Subtotal Federal Tax**				2,148,549	579,458	38,160,522	40,187,149	0	1,670,848	2,128,384	20,056,529	0	0	18,103,993
8	Income Tax	Income Tax	Montana	2024	0	(418,016)	(46,842)	109,713	0	0	(261,461)	(3,200)	0	0	(43,642)
9	County & City Income Tax	Income Tax	Oregon	2024	0	1,656,060	40,811	1,097,781	0	0	2,713,030	154,178	0	0	(113,367)
10	**Subtotal Income Tax**				0	1,238,044	(6,031)	1,207,494	0	0	2,451,569	150,978	0	0	(157,009)
11	Electric Energy Producers Tax	Other License And Fees Tax	Montana	2024	191,151	0	898,424	847,301	0	242,274	0	524,648	0	0	373,776
12	**Subtotal Other License And Fees Tax**				191,151	0	898,424	847,301	0	242,274	0	524,648	0	0	373,776
13	Property Taxes	Property Tax	Montana	2024	2,077,279	0	6,643,568	5,527,151	0	3,193,696	0	5,462,741	0	0	1,180,827
14	Property Taxes	Property Tax	Oregon	2024	0	42,205,833	87,519,641	91,386,718	0	0	46,072,910	82,859,635	0	0	4,660,006
15	Property Taxes	Property Tax	Washington	2024	1,731,244	0	1,624,855	1,640,832	0	1,715,267	0	1,624,855	0	0	0
16	**Subtotal Property Tax**				3,808,523	42,205,833	95,788,064	98,554,701	0	4,908,963	46,072,910	89,947,231	0	0	5,840,833
17	Corp Excise Tax and CAT	Excise Tax	Oregon	2024	243,008	(445,867)	11,083,046	16,994,929	0	0	5,223,008	12,715,804	0	0	(1,632,758)
18	**Subtotal Excise Tax**				243,008	(445,867)	11,083,046	16,994,929	0	0	5,223,008	12,715,804	0	0	(1,632,758)
19	City Taxes & Licenses	Franchise Tax	Oregon	2024	4,008,281	0	63,128,954	57,568,787	1	9,568,449	0	62,931,166	0	0	197,788
20	Corporate Franchise Tax	Franchise Tax	California	2024	0	(1,318,757)	695,945	550,000	0	0	(1,464,702)	722,278	0	0	(26,333)
21	**Subtotal Franchise Tax**				4,008,281	(1,318,757)	63,824,899	58,118,787	1	9,568,449	(1,464,702)	63,653,444	0	0	171,455
22	Unemployment	Payroll Tax	Oregon	2024	1,549,307	0	4,697,125	4,086,216	1	2,160,217	0	1,736,694	0	0	2,960,431
23	Transportation Tax	Payroll Tax	Oregon	2024	75,874	0	2,517,858	2,037,349	(1)	556,382	0	1,161,932	0	0	1,355,926
24	Workers Comp Assessment	Payroll Tax	Oregon	2024	18	0	217,538	296,445	1	(78,888)	0	93,153	0	0	124,385
25	**Subtotal Payroll Tax**				1,625,199	0	7,432,521	6,420,010	1	2,637,711	0	2,991,779	0	0	4,440,742
26	Other State Income Tax	State Tax	Various	2024	0	8,418	2,731	2,506	(257)	0	8,450	0	0	0	2,731
27	**Subtotal State Tax**				0	8,418	2,731	2,506	(257)	0	8,450	0	0	0	2,731
28	Department of Energy	Other Taxes and Fees	Oregon	2024	0	1,110,595	2,542,332	2,378,665	0	0	946,928	2,688,675	0	0	(146,343)
29	Public Utility Comm Fees	Other Taxes and Fees	Oregon	2024	0	0	13,349,480	13,349,480	0	0	0	0	0	0	13,349,480
30	Department of Enviro Quality	Other Taxes and Fees	Oregon	2024	187,439	0	246,958	264,689	0	169,708	0	0	0	0	246,958
31	Water Power Fee	Other Taxes and Fees	Oregon	2024	0	434,244	694,942	62,136	0	0	(198,562)	0	0	0	694,942

32	Goods & Services Tax	Other Taxes and Fees	Canada	2024	(162)	0	0	0	0	(162)	0	0	0	0	0
33	**Subtotal Other Taxes and Fees**				187,277	1,544,839	16,833,712	16,054,970	0	169,546	748,366	2,688,675	0	0	14,145,037
40	TOTAL				12,211,988	43,811,968	234,017,888	238,387,847	(255)	19,197,791	55,167,985	192,729,088		0	41,288,800

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
1	Electric Utility									
2	Electric Utility	497,448	411.4	60,422,917	411.4	127,794	(121,253)	60,671,318	18.72 years	Return to Provision true-up
8	TOTAL Electric (Enter Total of lines 2 thru 7)	497,448		60,422,917		127,794	(121,253)	60,671,318		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
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47											
47	OTHER TOTAL										
48	GRAND TOTAL	497,448						60,671,318			

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Tenant security deposits	159,324			676	160,000
2	Deferred Liability for Transferred Non-Qualified Plan Benefits	479,562	421	18,353		461,209
3	Reserve for Environmental Remediation Costs	4,000,000				4,000,000
4	Clean Fuels Program OPUC 17-250 and 17-512	30,442,201	107,154,182,184,232,253,254,903,908,935	15,258,856	5,464,729	20,648,074
5	Wireless Mods & Make Ready Clearing	1,696,720			3,011	1,699,731
6	Equity Forward Transaction Credit	0	232	23,455		(23,455)
7	AED: Grant Implementation	10,000			125,000	135,000
47	TOTAL	36,787,807		15,300,664	5,593,416	27,080,559

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			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)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other										
5.2	Other										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other										
12.2	Other										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	0									0
18	Classification of TOTAL										
19	Federal Income Tax										
20	State Income Tax										
21	Local Income Tax										

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				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			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)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	876,069,126	554,365,262	44,243,228				973,053,319		531,289,914	944,427,755
3	Gas	0									0
4	Other (Specify)	0									0
5	Total (Total of lines 2 thru 4)	876,069,126	554,365,262	44,243,228	0	0		973,053,319		531,289,914	944,427,755
6											
7											
8											0
9	TOTAL Account 282 (Total of Lines 5 thru 8)	876,069,126	554,365,262	44,243,228	0	0		973,053,319		531,289,914	944,427,755
10	Classification of TOTAL										
11	Federal Income Tax	692,291,506	425,939,806	31,371,929			182.3	548,846,894	254	207,900,819	745,913,308
12	State Income Tax	181,753,384	128,058,130	12,831,934			182.3	397,211,188	254	296,004,949	195,773,341
13	Local Income Tax	2,024,236	367,326	39,365			182	26,995,237	254	27,384,146	2,741,106

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	ADJUSTMENTS Debits Amount (h)	ADJUSTMENTS Credits Account Debited (i)	ADJUSTMENTS Credits Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Property Related	14,725,669					254	164,764,987	182.3	162,240,537	12,201,219
4	Price Risk Management	48,566,149	21,298,667	24,523,877				1,471,104		1,151,157	45,020,992
5	Regulatory Assets	96,180,448	103,681,400	80,585,059				5,521,321		6,767,328	[(a)] 120,522,796
6	Regulatory Liabilities									2,556,555	2,556,555
7	Other	16,780,452	667,532	308,788				473,518		924,878	[(b)] 17,590,556
9	TOTAL Electric (Total of lines 3 thru 8)	176,252,718	125,647,599	105,417,724				172,230,930		173,640,455	197,892,118
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	9,935,225			6,552,681	2,308,241	254	261,015	182.3	319,954	[(c)] 14,238,604
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	186,187,943	125,647,599	105,417,724	6,552,681	2,308,241		172,491,945		173,960,409	212,130,722
20	Classification of TOTAL										
21	Federal Income Tax	128,888,408	88,754,453	74,305,457	4,643,721	1,613,407		120,339,771		122,530,539	148,558,486
22	State Income Tax	51,598,056	36,787,442	31,024,517	1,903,210	692,884		41,609,976		40,917,602	57,878,933
23	Local Income Tax	5,701,479	105,704	87,750	5,750	1,950		10,542,198		10,512,268	5,693,303

NOTES

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Regulatory Assets:	Beginning Balance	Ending Balance
ASC 715 Pension & Post Retirement	28,657,427	23,167,408
ASC 980 Mark-to-Market	17,540,735	19,156,256
Miscellaneous	(86,720)	14,716,046
Decoupling	960,668	(38,979)
Feed in Tariff (FIT)	21,276,988	116,786
Portland Harbor (PHERA)	8,325,655	8,897,516
Covid-19	3,327,888	(399,494)
Wildfire	91,750	7,832,427
Storm Deferral	13,156,358	20,645,550
PCAM Deferral	3,185,930	23,635,749
PTC Transfer	0	2,793,531
Subtotal Regulatory Assets	**96,180,448**	**120,522,796**

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Other (Utility):	Beginning Balance	Ending Balance
Prepaid Property Tax	11,291,514	11,899,430
Unamortized Loss on Reacquired Debt	4,453,808	4,127,470
Local Flow-Through Deferred Income Tax	1,035,130	1,563,656
Subtotal Other (Utility)	**16,780,452**	**17,590,556**

(c) Concept: AccumulatedDeferredIncomeTaxesOther

Other (Non-Utility):	Beginning Balance	Ending Balance
Other	9,491,534	14,156,482
TOLI	197,177	(18,721)
Decoupling	246,514	91,843
Subtotal Other (Non-Utility)	**9,935,225**	**14,238,604**

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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 Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Excess Deferred Income Taxes	233,062,687	190	214,691,672	218,977,654	237,348,669
2	Gain on Asset Sales (Per OPUC Order No. 01-777 dtd 8/31/2001).	(51,336)	407.4 / 421	38,816	90,152	0
3	Boardman Severance (Advice No.14-18, dtd 11/3/2014)	0	456	8,692	8,692	0
4	Asset Retirement Obligations: Balancing Account	2,654,643	407.3	16,575,640	13,920,998	1
5	Boardman ARO	1,017,805	182.3 / 407.3	1,017,804	0	1
6	Colstrip Major Maintenance Deferral (Per OPUC UE-319, Order No. 17-511, dtd 12/18/17)	5,267,095	254 / 456	4,236,787	983,847	2,014,155
7	Port Westward 1 Major Maint Deferral (Per OPUC UE 262, Order No. 13-459, dtd 12/9/2013)	2,752,945	182.3 / 254 / 456	4,829,132	2,076,187	0
8	Port Westward 2 Major Maintenance Deferral (Per OPUC 2015 GRC Docket UE-283, OPUC Order No.14-422, dtd 12/4/2014)	4,212,298	254 / 456	2,162,409	773,804	2,823,693
9	Zero Interest Program Loan Repayments (Per Advice No. 05-19 dtd 12/20/2005)	128,639		0	62,057	190,696
10	Schedule 110 Energy Efficiency - Balancing Account (Per Advice No. 07-25 dtd 5/20/2008).	1,252,806	182.3 / 254 / 407.3 / 421	62,622	160,669	1,350,853
11	Sunway 3 Investment Deferral (Per UM 1480 dtd 4/01/2010; Amortization over 20 years commencing 2010)	295,510	407.4	45,480	0	250,030
12	Trojan Decommissioning Deferral (Per OPUC UE-319, Order No.17-511, dtd 12/18/2017).	(3,447)	407 / 421	11,831	28	(15,250)
13	PRC Acquisition (Per OPUC UE-283 Final GRC Order No.14-422, dtd 12/04/2014, Second Partial Stipulation dtd 9/2/2014)	0		0	250,670	250,670
14	Deferred Broker Settlement	2,864,908	182.3	8,812,036	5,947,128	0
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 12/31/2024.	0	182.3 / 254 / 421	5,801,075	5,801,075	0
16	Research & Development Tax Credits (Per UM-1991, OPUC Order No. 18-464 dtd 12/14/2018), Amortizing through 12/31/2024.	907,501	190 / 407.4 / 411.1 / 923	975,421	2,139,651	2,071,731
17	Postretirement Plans (Per SFAS No. 158 adopted 12/31/2006; OPUC Order No. 07-051 dtd 2/12/2007)	2,938,301	219	1,577,586	666,861	2,027,576
18	OCAT (Per UM-2037, UE 368, Order No. 20-029, dtd 01/29/2020), Amortizing through 12/31/2024.	3,505,887	407.4	3,243,246	108,312	370,953
19	Demand Response Testbed (Per OPUC Order No. 19-425, dtd 12/06/2019), Amortizing through 12/31/2024	1	182.3 / 232 / 254 / 421	2,076,774	3,037,783	961,010
20	Deferred Cost - FLEX Pricing Program (Per OPUC Order No. 19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2024.	2,247,457	182.3 / 254	1,371,335	188,809	1,064,931
21	Automated Demand Response Cost Recovery Mechanism (Per OPUC Advice No. 17-29, dtd 11/13/17), Amortizing through 12/31/2024.	1,127,511	182.3 / 254 / 407.3	872,214	1,033,904	1,289,201
22	Deferred Cost - DLC Thermostat (Per OPUC Order No.19-313 dtd 9/26/19, UM 1708), Amortizing through 12/31/2024.	703,343	182.3 / 254	635,210	1,425,665	1,493,798
23	Multifamily Water Heater (Per Advice Filing No. 17-06, UM-1827, Order No. 17-224, dtd 6/27/2017), Amortizing through 12/31/2024.	1,098,198	182.3 / 254	365,782	502,014	1,234,430
24	Wheatridge RECs (UE 391), Amortizing through 12/31/2024.	4,991,746	555	4,614,000	5,565,735	5,943,481
25	Transportation Electrification (UM 1938).	226,009	182.3 / 254	281,458	448,779	393,330
26	HB-2165 (UM 2218), Amortizing through 12/31/2024.	10,376,102	107 / 143 / 182.3 / 232 / 253 / 254 / 431 / 908 / 921	8,990,698	12,824,265	14,209,669
27	Monet NVPC QF Deferral 2021 (UM 1988).	118,803	254	118,803	0	0
28	Monet NVPC QF Deferral 2022 (UM 1988), Amortizing through 12/31/2024.	106,716	555	104,244	0	2,472
29	Regional Power Act (RPA)	33,408		0	0	33,408
30	Direct Access 2023 (Per UM-1301), Amortizing through 12/31/2024.	2,715,256	232 / 447	2,503,969	190,955	402,242

31	Residual Deferred Account (per OPUC Order No. 10-279 dtd 7/23/2010)	202,744		0	91,899	294,643
32	EV Charging (Per UM 2003, Order No. 20-381, dtd 10/27/2020), Amortizing through 12/31/2024.	599,146	182.3 / 184 / 232 / 254 / 921	903,983	1,462,082	1,157,245
33	Income Qualified Bill Discounts (UM 2219), Amortizing through 12/31/2024.	52,906		0	3,611,682	3,664,588
34	KB Pipeline MMA (UE-394, 5/09/2022, amortization of 5 years)	20,643	456	760	26,764	46,647
35	CBIAG Deferral (UM 2249) Advice No. 22-36. Amortizing through 12/31/2024.	315,767	182.3 / 254	359,009	273,956	230,714
36	Coyote Springs Major Maintenance Accrual LTSA (per OPUC GRC 95-1216, dtd 11/20/1995)	144,006	254 / 456	1,746,885	1,875,940	273,061
37	Residential Battery Energy Storage Pilot (Per UM-2078, Order No. 20-208, dtd 7/6/2020).	316,261	182.3 / 254	556,022	239,761	0
38	RVM Deferral (Per OPUC Order 23-386 UE-416)	0	182.3 / 593	2,934,072	2,934,072	0
39	Clearwater Deferral (Per Advicee No. 23-20, UE-427) Renewable Resource Automatic Adjustment Clause (RAAC).	0	449.1	46,031,411	85,577,441	39,546,030
41	TOTAL	286,202,265		338,556,878	373,279,291	320,924,678

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	1,406,370,635	1,208,401,408	7,731,594	7,952,313	829,721	815,920
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	(a)904,898,637	(e)790,602,966	6,466,018	6,557,723	113,724	112,469
5	Large (or Ind.) (See Instr. 4)	(b)457,455,750	(f)367,911,469	5,032,385	4,578,148	281	266
6	(444) Public Street and Highway Lighting	14,304,206	13,078,454	42,625	43,544	218	204
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	2,783,029,228	2,379,994,297	19,272,622	19,131,728	943,944	928,859
11	(447) Sales for Resale	588,094,149	476,723,920	10,305,039	7,803,299	41	45
12	TOTAL Sales of Electricity	3,371,123,377	2,856,718,217	29,577,661	26,935,027	943,985	928,904
13	(Less) (449.1) Provision for Rate Refunds	36,929,618	(14,313,659)				
14	TOTAL Revenues Before Prov. for Refunds	3,334,193,759	2,871,031,876	29,577,661	26,935,027	943,985	928,904
15	Other Operating Revenues						
16	(450) Forfeited Discounts	7,772,424	6,862,843				
17	(451) Miscellaneous Service Revenues	(c)1,432,181	(g)1,541,350				
18	(453) Sales of Water and Water Power	(33,602)	(28,980)				
19	(454) Rent from Electric Property	19,666,388	18,968,002				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	(d)73,639,396	(h)62,261,243				
22	(456.1) Revenues from Transmission of Electricity of Others	24,044,195	5,914,686				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	126,520,982	95,519,144				
27	TOTAL Electric Operating Revenues	3,460,714,741	2,966,551,020				

Line12, column (b) includes $ 41,005,000 of unbilled revenues.
Line12, column (d) includes 219,530 MWH relating to unbilled revenues

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $9,557,608 in revenue related to the delivery of 514,842 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 2024, 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 $22,389,721 in revenue related to the delivery of 1,909,068 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2024, 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:	2024
Boardman Decomm Balance Account	7,746,924
Boardman Severance	8,692
Colstrip Decommissioning	56,359
Colstrip Major Maint. Deferral	3,252,940
Coyote Springs Major Maint. Deferral	(129,056)
Firm PTP prepayment	113,259
Gain(Loss) on Gas Resale	(485,179)
Hydro License Implementation and Compliance	1,169,088
Lost Revenue Recovery	(1,844,561)
Other	2,938,975
PW1 Major Maint. Deferral	2,752,945
PW2 Major Maint. Deferral	1,388,603
RPA Balancing	53,484,293
Sch. 32 Sales Norm Adj	(3,281,523)
Sch. 7 Sales Norm Adj	(1,072,000)
Sch. 83 Sales Norm Adj	(825,459)
Steam Sales	3,022,478
Time of Day Deferral	4,342,273
Transmission Resale	1,000,345
Grand Total	73,639,396

(e) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $7,631,920 in revenue related to the delivery of 577,115 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 2023, 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 $18,532,651 in revenue related to the delivery of 1,715,095 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2023, 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/Test Charges

NWCPUD Scheduling

Reconnect Charges

Returned Check Charges

(h) Concept: OtherElectricRevenue

Other Electric Revenues consist of the following:	Q4-2023
Boardman Decommissioning Balancing Account	1,256
Boardman Inventory Write-Off	11,319
Boardman Severance	(44,018)
Carty - Major Maint Accrual/Defr	2,754,488
Colstrip - Major Maint Accrual/Defr	(213,452)
Colstrip Decommissioning	(10,284)
Coyote Springs - Major Maint Accrual/Defr	(144,006)
Customers Attaching PGE Poles	65,501
Firm PTP Prepayment	314,362
Gain(Loss) on Gas Resale	(783,923)

General Parks & Recreation	7,941
Hydro License Implementation and Compliance	1,115,513
Joint Affected System Study	180,000
KB Pipeline MMA Deferral	(20,644)
Lost Revenue Recovery	(1,005,911)
MCI Metro	760,421
Other	544,581
PW1 - Major Maint Deferral	796,273
PW2 - Major Maint Deferral	337,064
RPA Balancing	57,012,382
Sch. 32 Norm Adj	(4,503,256)
Sch. 7 Norm Adj	(114,000)
Sch. 83 Norm Adj	(2,417,092)
Steam Sales	4,365,520
Transmission Resale	2,981,210
Transmission Study Fees	270,000
Grand Total	62,261,243

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
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45					
46	TOTAL				

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	7-Residential Service	7,721,511	1,392,460,229	829,721	9,306.1535	0.1803
2	15-Outdoor Area Lighting	1,609	854,406	0		0.531
41	TOTAL Billed Residential Sales	7,723,120	1,393,314,635	829,721	9,308.0927	0.1804
42	TOTAL Unbilled Rev. (See Instr. 6)	8,474	13,056,000			1.5407
43	TOTAL	7,731,594	1,406,370,635	829,721	9,318.3058	0.1819

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	15-Outdoor Area Lighting	11,254	3,245,953	0		0.2884
2	32-Small Nonresidential	1,512,933	263,441,674	96,011	15,757.9132	0.1741
3	38-Large Nonresidential	28,526	5,194,515	364	78,368.1319	0.1821
4	47-Small Irrigation & Drainage	18,505	4,746,124	2,763	6,697.4303	0.2565
5	49-Large Irrigation & Drainage	56,823	12,543,826	1,300	43,710	0.2208
6	83-Large Nonresidential	2,809,505	370,342,219	11,619	241,802.6508	0.1318
7	85-Large Nonresidential	2,010,303	227,502,975	1,231	1,633,064.9878	0.1132
8	89-Large Nonresidential	(6,847)	(401,329)	1	(6,847,000)	0.0586
9	485-Large Nonresidential	20,467	2,054,586	12	1,705,583.3333	0.1004
10	485-Large Nonresidential DAS	0	8,846,443	200	0	
11	489-Large Nonresidential DAS	0	355,210	1	0	
12	515-Outdoor Area Lighting DAS	0	606	0		
13	532-Small Nonresidential DAS	0	169,302	120	0	
14	538-Large Nonresidential Opt. DAS	0	969	2	0	
15	583-Large Nonresidential DAS	0	234,497	74	0	
16	585-Large Nonresidential DAS	0	(205,933)	26	0	
41	TOTAL Billed Small or Commercial	6,461,469	898,071,637	113,724	56,817.1098	0.139
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	4,550	6,827,000			1.5004
43	TOTAL Small or Commercial	6,466,018	[a]904,898,637	113,724	56,857.119	0.1399

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenue

Includes $9,557,608 in revenue related to the delivery of 514,842 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 2024, 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: 04/11/2025	Year/Period of Report End of: 2024/ 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	85-Large Nonresidential	589,022	61,274,748	176	3,346,715.9091	0.104
2	89-Large Nonresidential	1,066,117	96,867,784	24	44,421,541.6667	0.0909
3	90-Large Nonresidential	3,122,595	253,368,499	6	520,432,500	0.0811
4	485-Large Nonresidential	17,545	1,347,484	1	17,545,000	0.0768
5	489-Large Nonresidential	30,598	1,860,064	1	30,598,000	0.0608
6	485-Large Nonresidential DAS	0	5,424,518	50	0	
7	489-Large Nonresidential DAS	0	11,799,243	18	0	
8	585-Large Nonresidential DAS	0	(52,521)	2	0	
9	689-Large Nonresidential DAS	0	4,443,931	3	0	
41	TOTAL Billed Large (or Ind.) Sales	4,825,877	436,333,750	281	17,173,939.5018	0.0904
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	206,506	21,122,000			0.1023
43	TOTAL Large (or Ind.)	5,032,385	[a]457,455,750	281	17,908,836.2989	0.0909

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue

Includes $22,389,721 in revenue related to the delivery of 1,909,068 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2024, 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: 04/11/2025	Year/Period of Report End of: 2024/ 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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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	91-Street & Hwy Lighting	9,908	4,833,060	200	49,540	0.4878
2	92-Traffic Signals	2,749	274,185	16	171,812.5	0.0997
3	95-Street & Hwy Lighting	29,968	9,196,961	2	14,984,000	0.3069
41	TOTAL Billed Public Street and Highway Lighting	42,625	14,304,206	218	195,527.5229	0.3356
42	TOTAL Unbilled Rev. (See Instr. 6)	0	0			
43	TOTAL	42,625	14,304,206	218	195,527.5229	0.3356

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	Transmission Rate Case	0	36,929,618	0		
41	TOTAL Billed Provision For Rate Refunds	0	36,929,618	0		
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		36,929,618			

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	19,053,091	2,742,024,228	943,944	20,184.5565	0.1439
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	219,530	41,005,000			0.1868
43	TOTAL - All Accounts	19,272,621	2,783,029,228	943,944	20,417.1233	0.1444

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	Alberta Electric System Operator (AESO)	SF	AESO				20,790	0	928,653	0	928,653
2	Altop Energy Trading LLC	SF	WSPP-1				12,737	0	513,974	0	513,974
3	J Aron & Company	SF	EEI				4,400	0	217,472	0	217,472
4	Arizona Public Service Co.	SF	WSPP-1				1,050	0	128,500	0	128,500
5	Avangrid Renewables (was Iberdrola)	SF	EEI				115,044	0	4,547,654	0	4,547,654
6	Atlas Energy, LLC	SF	EEI				601,084	0	27,234,028	0	27,234,028
7	Avista Corp.	SF	WSPP-1				21,217	0	1,415,264	0	1,415,264
8	BP Energy Company	SF	PGE-11				18,345	0	2,382,354	0	2,382,354
9	Black Hills Power, Inc.	SF	WSPP-1				498	0	24,495	0	24,495
10	Bonneville Power Administration	SF	WSPP-1				1,583,527	0	91,902,892	0	91,902,892
11	British Columbia Hydro & Power Authoirty	SF	WSPP-1				12	0	0	0	0
12	Brookfield Energy Marketing LP	SF	WSPP-1				91,574	0	3,629,421	0	3,629,421
13	California Independent System Operator	SF	CAISO				1,608,842	0	59,241,166	0	59,241,166
14	Calpine Energy Services, L.P.	SF	EEI				54,573	0	1,933,828	0	1,933,828
15	Calpine Energy Services	OS	EEI				0	0	0	21,175,000 [(b)]	21,175,000
16	Chelan County, PUD No. 1, Washington	SF	WSPP-1				7	0	140	0	140
17	Citigroup Energy Inc.	SF	WSPP-1				42,838	0	2,968,773	0	2,968,773
18	City of Anaheim	OS	WSPP-1				0	0	0	7,500,000 [(c)]	7,500,000
19	City of Burbank	SF	WSPP-1				0	0	0	0	0
20	City of Redding	SF	WSPP-1				1,050	0	42,000	0	42,000
21	City of Glendale	SF	WSPP-1				0	0	0	0	0
22	City of Roseville	SF	WSPP-1				60	0	2,400	0	2,400

23	City of Rancho Cucamonga	OS	REC				0	0	0	1,650,000[d]	1,650,000
24	Clatskanie Peoples Utility District	SF	WSPP-1				1,880	0	129,884	0	129,884
25	Clean Power Alliance	OS	WSPP-1				0	0	0	0	0
26	ConocoPhillips Company	SF	WSPP-1				76,701	0	3,634,319	0	3,634,319
27	Constellation	OS	EEI				0	0	0	18,744,447[e]	18,744,447
28	CP Energy Marketing (US) Inc	SF	WSPP-1				16,128	0	832,414	0	832,414
29	Direct Energy Business Marketing	SF	WSPP-1				0	0	0	0	0
30	Direct Energy Business Marketing	OS	WSPP-1				0	0	0	2,040,000[f]	2,040,000
31	Douglas County, PUD No. 1, Washington	LU	WSPP-1				1,394,235	0	16,340,191	0	16,340,191
32	Dynasty Power	SF	WSPP-1				283,529	0	11,064,738	0	11,064,738
33	EAST BAY COMMUNITY ENERGY AUTHORITY	OS	WSPP-1				0	0	0	8,600,000[g]	8,600,000
34	EDF Trading North America, LLC	SF	WSPP-1				13,208	0	656,350	0	656,350
35	Energy Keepers, Inc.	SF	WSPP-1				37,963	0	2,333,994	0	2,333,994
36	ENMAX Energy Marketing Inc.	SF	EEI				433	0	52,747	0	52,747
37	Eugene Water & Electric Board	SF	WSPP-1				12,778	0	526,859	0	526,859
38	Exelon Generation Company, LLC	SF	EEI				37,297	0	1,386,290	0	1,386,290
39	Exelon Generation Company, LLC	OS	EEI				0	0	0	0	0
40	Gridforce Energy Management	SF	NWPP				726	0	104,552	0	104,552
41	Guzman Energy LLC	SF	WSPP-1				10,205	0	419,328	0	419,328
42	Idaho Power Company	SF	WSPP-1				74,652	0	3,402,037	0	3,402,037
43	Load Balance Energy	OS	OATT				(3,027)	0	0	0	0
44	Los Angeles Dept. Water Power	SF	WSPP-1				0	0	0	0	0
45	Los Angeles Dept. Water Power	OS	WSPP-1				0	0	0	0	0
46	Macquarie Energy LLC	SF	WSPP-1				46,649	0	2,299,002	0	2,299,002
47	Mercuria Energy America, LLC	SF	WSPP-1				327,033	0	17,752,589	0	17,752,589
48	Merrill Lynch Commodities	SF	WSPP-1				54,983	0	3,032,815	0	3,032,815
49	Morgan Stanley Capital Group, Inc.	SF	PGE-11				54,647	0	2,157,701	0	2,157,701
50	Marin Clean Energy	OS	WSPP-1				0	0	0	0	0
51	NaturEner Power Watch, LLC	SF	NWPP				22	0	618	0	618
52	NorthWestern Corporation	SF	WSPP-1				18,925	0	1,463,405	0	1,463,405
53	Nevada Power	SF	WSPP-1				500		23,000	0	23,000
54	PacifiCorp	SF	EEI				91,694	0	5,159,931	0	5,159,931
55	PacifiCorp	LU	PGE-11				17,012	0	122,409	0	122,409
56	Powerex Corp.	SF	EEI				831,785	0	26,406,193	0	26,406,193
57	Okanogan County PUD, Washington	LU	WSPP-1				146,490	0	14,937,887	0	14,937,887
58	Orange County	OS	WSPP-1				0	0	0	0	0
59	Phillips 66 Energy Trading LLC	SF	WSPP-1				85,021	0	2,387,203	0	2,387,203
60	Public Utility District No. 1 of Clark County	SF	WSPP-1				0	0	0	0	0
61	Public Utility District No. 2 of Grant County	SF	WSPP-1				1,268,075	0	121,203,549	0	121,203,549
62	Public Service Company of Colorado	SF	WSPP-1				0	0	0	0	0
63	Puget Sound Energy	SF	WSPP-1				24,074	0	3,654,485	0	3,654,485
64	Rainbow Energy Marketing Company	SF	WSPP-1				516	0	24,115	0	24,115
65	San Jose Clean Energy	OS	WSPP-1				0	0	0	0	0
66	Sacramento Municipal Utility District	SF	WSPP-1				29,154	0	3,733,479	0	3,733,479
67	Sacramento Municipal Utility District	OS	WSPP-1				0	0	0	0	0
68	San Diego CP	OS	WSPP-1				0	0	0	0	0

69	San Diego Gas and Electric	SF	WSPP-1				400	0	35,600	0	35,600
70	Seattle City Light	SF	WSPP-1				7,578	0	291,400	0	291,400
71	Shell Energy North America (US), L.P.	SF	PGE-11				128,231	0	5,672,746	0	5,672,746
72	Shell Energy North America (US), L.P.	OS	WSPP-1				0	0	0	[(b)] 6,750,000	6,750,000
73	Snohomish County, PUD No.1, Washington	SF	WSPP-1				8,561	0	1,128,193	0	1,128,193
74	Sonoma Clean Power Authority	OS	WSPP-1				0	0	0	0	0
75	Southern California Edison	SF	EEI				268,071	0	29,664,154	0	29,664,154
76	Tacoma Power	SF	WSPP-1				3,678	0	120,817	0	120,817
77	Tenaska Power Services Co.	SF	WSPP-1				0	0	[(a)] (680,237)	0	(680,237)
78	The Energy Authority, Inc.	SF	WSPP-1				33,933	0	1,790,964	0	1,790,964
79	TransAlta Energy Marketing (U.S.), Inc.	SF	EEI				318,359	0	15,954,281	0	15,954,281
80	TransCanada Energy Sales Ltd.	SF	WSPP-1				11,918	0	585,426	0	585,426
81	Turlock Irrigation District	SF	WSPP-1				57,302	0	5,266,001	0	5,266,001
82	Vitol Inc.	SF	WSPP-1				336,072	0	16,235,237	0	16,235,237
83	Umatilla Electric Cooperative	SF	EEI				0	0	0	0	0
84	WAPA-Sierra Nevada Region	SF	NWPP				0	0	0	0	0
85	Warm Springs Power Enterprises	OS	WSPP-1				0	0	0	0	0
86	Western Area Power Authority	SF	NWPP				0	0	0	0	0
87	Direct Access deferral 2022						0	0	0	[(i)] 762,528	762,528
88	Direct Access Deferral						0	0	0	[(j)] 2,452,494	2,452,494
89	Portland General Electric Total	SF	OA96137	251.0386			0	0	0	[(k)] 0	0
15	Subtotal - RQ										0
16	Subtotal-Non-RQ						10,305,039	0	518,419,680	69,674,469	588,094,149
17	Total						10,305,039	0	518,419,680	69,674,469	588,094,149

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: EnergyChargesRevenueSalesForResale

Represents the write off of a receivable from prior period

(b) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to

Calpine.

(c) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to

City of Anaheim

(d) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to

City of Rancho Cucamonga

(e) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to

Constellation

(f) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to

Direct Business Energy Marketing

(g) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to

EAST BAY COMMUNITY ENERGY AUTHORITY

(h) Concept: OtherChargesRevenueSalesForResale

Represents sales of renewable energy credits to

Shell Energy North America (US), L.P.

(i) Concept: OtherChargesRevenueSalesForResale

Defer costs associated with the implementation of the annual

direct access open enrollment window. See Tariff Schedule 128

filed 01/26/2007.

(j) 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.

(k) Concept: OtherChargesRevenueSalesForResale

Represents Portland General Electric Companys use of Portland

General Electric Company's Open Access Transmission

System. This is included in Account 447 based on guidance

from FERC Deputy Chief Accountant - issued January 1996.

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	(19,472)	(184,198)
5	(501) Fuel	44,941,266	48,621,978
6	(502) Steam Expenses	1,927,250	1,833,604
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	4,353,002	3,329,744
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	51,202,046	53,601,128
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	550,751	361,016
16	(511) Maintenance of Structures	1,146,854	989,089
17	(512) Maintenance of Boiler Plant	11,072,782	7,928,015
18	(513) Maintenance of Electric Plant	1,808,495	707,045
19	(514) Maintenance of Miscellaneous Steam Plant	665,313	678,451
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	15,244,195	10,663,616
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	66,446,241	64,264,744
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	1,508,981	492,820
45	(536) Water for Power	648,128	628,018
46	(537) Hydraulic Expenses	8,064,162	7,510,409
47	(538) Electric Expenses	1,732,650	2,066,432
48	(539) Miscellaneous Hydraulic Power Generation Expenses	5,701,559	3,322,249
49	(540) Rents	1,203,744	1,184,410
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	18,859,224	15,204,338
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,091,789	538,154
54	(542) Maintenance of Structures	2,051	0
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,855,418	908,643
56	(544) Maintenance of Electric Plant	1,280,134	1,162,927
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,204,595	2,028,513
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	7,433,987	4,638,237
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	26,293,211	19,842,575
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	3,300,300	4,066,606
63	(547) Fuel	412,823,864	342,068,772
64	(548) Generation Expenses	15,352,608	17,766,638
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	21,518,284	13,819,783
66	(550) Rents	466,602	445,135
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	453,461,658	378,166,934
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	2,105,461	2,376,757
70	(552) Maintenance of Structures	710,948	471,034
71	(553) Maintenance of Generating and Electric Plant	49,718,253	44,425,815
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,388,770	1,062,729
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	53,923,432	48,336,335
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	507,385,090	426,503,269
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	879,859,761	777,351,053
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	85,796	271,108
78	(557) Other Expenses	33,806,989	27,132,622
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	913,752,546	804,754,783
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	1,513,877,088	1,315,365,371
81	2. TRANSMISSION EXPENSES		
82	Operation		

83	(560) Operation Supervision and Engineering	5,134,747	6,378,440
85	(561.1) Load Dispatch-Reliability	16,278	17,296
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,946,997	1,574,577
87	(561.3) Load Dispatch-Transmission Service and Scheduling	2,396,290	2,093,541
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	130,926	237,602
90	(561.6) Transmission Service Studies	1,554	402
91	(561.7) Generation Interconnection Studies	833,374	574,815
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	412,928	341,550
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	942,895	470,672
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	133,286,845	105,365,945
97	(566) Miscellaneous Transmission Expenses	714,483	(3,198,359)
98	(567) Rents	3,331,468	3,166,516
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	149,148,785	117,022,997
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	185,609	6,503
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	456,950	1,039,524
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,403,828	1,530,913
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	6,609,506	4,593,349
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of Lines 101 thru 110)	9,655,893	7,170,289
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	158,804,678	124,193,286
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	14,493,893	24,206,115
135	(581) Load Dispatching	1,988,611	1,149,996
136	(582) Station Expenses	572,797	2,038,686
137	(583) Overhead Line Expenses	3,087,865	3,175,367
138	(584) Underground Line Expenses	5,229,646	4,673,855
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	282,807	196,111
140	(586) Meter Expenses	2,893,636	3,406,006
141	(587) Customer Installations Expenses	2,031,653	1,874,740
142	(588) Miscellaneous Expenses	13,391,406	10,771,426
143	(589) Rents	1,917,996	1,475,545
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	45,890,310	52,967,847
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	7,087,550	158,167
147	(591) Maintenance of Structures	276,588	311,339
148	(592) Maintenance of Station Equipment	7,362,864	5,619,940
148.1	(592.2) Maintenance of Energy Storage Equipment	14,032	45,693
149	(593) Maintenance of Overhead Lines	141,052,908	117,148,533
150	(594) Maintenance of Underground Lines	16,959,864	13,106,998
151	(595) Maintenance of Line Transformers	1,158,893	758,711
152	(596) Maintenance of Street Lighting and Signal Systems	737,776	523,919
153	(597) Maintenance of Meters	30,022	15,032
154	(598) Maintenance of Miscellaneous Distribution Plant	7,757,151	9,577,341
155	TOTAL Maintenance (Total of Lines 146 thru 154)	182,437,648	147,265,673
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	228,327,958	200,233,520
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	229,025	84,968
161	(903) Customer Records and Collection Expenses	51,327,753	50,269,699
162	(904) Uncollectible Accounts	24,616,881	13,685,188
163	(905) Miscellaneous Customer Accounts Expenses	8,790,163	5,229,586
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	84,963,822	69,269,441
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	26,885,040	28,557,075
169	(909) Informational and Instructional Expenses	1,998,021	1,644,319
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	28,883,061	30,201,394

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	158,308,949	108,668,690
182	(921) Office Supplies and Expenses	9,396,637	16,082,212
183	(Less) (922) Administrative Expenses Transferred-Credit	33,977,142	21,252,417
184	(923) Outside Services Employed	28,719,119	17,637,354
185	(924) Property Insurance	5,441,537	11,137,408
186	(925) Injuries and Damages	11,577,752	6,021,871
187	(926) Employee Pensions and Benefits	46,102,197	49,091,471
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	18,469,839	14,817,937
190	(929) (Less) Duplicate Charges-Cr.	3,604,720	3,277,091
191	(930.1) General Advertising Expenses	643,142	820,207
192	(930.2) Miscellaneous General Expenses	15,751,649	14,307,259
193	(931) Rents	813,781	3,900,473
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	257,642,740	217,955,374
195	Maintenance		
196	(935) Maintenance of General Plant	5,755,040	4,737,713
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	263,397,780	222,693,087
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	2,278,254,387	1,961,956,099

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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 ($) (k)	COST/SETTLEMENT OF POWER Energy Charges ($) (l)	COST/SETTLEMENT OF POWER Other Charges ($) (m)	COST/SETTLEMENT OF POWER Total (k+l+m) of Settlement ($) (n)
1	Airport Solar, LLC	LU	201				102,288	0	0	0	0	8,172,334	0	8,172,334
2	Alkali Solar	LU	201				26,312	0	0	0	0	2,435,368	0	2,435,368
3	Altop Energy Trading	SF	WSPP-1				3,200	0	0	0	0	184,344	0	184,344
4	Arizona Public Service	SF	WSPP-1				2	0	0	0	0	45	0	45
5	Avangrid Renewables (was Iberdrola)	SF	PGE-11				451,198	0	0	0	0	34,054,037	0	34,054,037
6	Avangrid Renewables (was berdrola Renewables)	LU	PGE-11				321,756	0	0	0	0	17,686,819	0	17,686,819
7	Avangrid Renewables (was Iberdrola)	LU	PGE-11				0	0	0	0	1,040,000	0	0	1,040,000
8	Avista Corp. - AVWP (was WWP)	SF	WSPP-1				234,308	0	0	0	0	10,474,832	0	10,474,832
9	Atlas Enery	SF	EEI				38,303	0	0	0	0	4,221,231	0	4,221,231
10	BP Energy Company	SF	PGE-11				7,352	0	0	0	0	398,352	0	398,352
11	Bakeoven II Solar PPA	LU	PGE-11				78,369	0	0	0	0	2,893,630	0	2,893,630
12	Brightwood Solar	LU	201				15,545	0	0	0	0	1,289,141	0	1,289,141
13	Ballston Solar	LU	201				3,586	0	0	0	0	355,825	0	355,825
14	Bellevue Solar	LU	Bellevue				0	0	0	0	0	160,950	0	160,950
15	Bonneville Power Administration	SF	WSPP-1				205,131	0	0	0	0	24,183,843	0	24,183,843
16	Bonneville Power Administration	LF	WSPP-1				1,062,783	0	0	0	0	58,494,589	0	58,494,589
17	Bonneville Power Administration	SF	WSPP-1				0	0	0	0	9,566,482	0	0	9,566,482
18	Boring Solar	LU	201				3,934	0	0	0	0	374,754	0	374,754
19	Brookfield Energy Marketing	SF	WSPP-1				8,139	0	0	0	0	355,881	0	355,881
20	CP Energy Marketing (US)	SF	WSPP-1				9,616	0	0	0	0	364,582	0	364,582
21	California Independent System Operator	SF	CAISO				1,525,934	0	0	0	0	64,384,035	0	64,384,035

22	Calpine Energy Services	SF	PGE-11				403,861	0	0	0	0	19,919,097	0	19,919,097
23	Case Creek Solar	LU	201				3,895	0	0	0	0	387,368	0	387,368
24	Bristol Solar LLC	LU	201				4,507	0	0	0	0	509	0	509
25	Butler Solar	LU	201				7,421	0	0	0	0	734,146	0	734,146
26	Chelan County, PUD No. 1, Washington	SF	WSPP-1				79,205	0	0	0	0	6,666,637	0	6,666,637
27	Citigroup Energy	SF	WSPP-1				31,094	0	0	0	0	1,533,312	0	1,533,312
28	Clatskanie County PUD	SF	WSPP-1				4,789	0	0	0	0	159,564	0	159,564
29	Clearwater East	LU	WSPP-1				364,427	0	0	0	0	14,146,109	0	14,146,109
30	Columbia Basin Electric Cooperative Inc.	LU	OATT				867	0	0	0	0	161,240	0	161,240
31	ConocoPhillips	SF	WSPP-1				433,669	0	0	0	0	36,697,657	0	36,697,657
32	Covanta Marion	LU	QF83-118				53,038	0	0	0	0	1,957,054	0	1,957,054
33	Day Hill Solar	LU	201				3,949	0	0	0	0	328,068	0	328,068
34	Dynasty Power Inc.	SF	WSPP-1				18,259	0	0	0	0	1,080,805	0	1,080,805
35	Douglas County, PUD No. 1, Washington	LF [b]	WSPP-1				2,100,369	0	0	0	0	70,191,149	0	70,191,149
36	Douglas County, PUD No. 1, Washington	SF	WSPP-1				0	0	0	0	30,047,293	0	0	30,047,293
37	EDF Trading North America, LLC	SF	WSPP-1				8,714	0	0	0	0	339,682	0	339,682
38	Energy Keepers, Inc. - ENKP	SF	WSPP-1				23,764	0	0	0	0	1,220,206	0	1,220,206
39	ENMAX Energy Marketing	SF	PGE-11				100	0	0	0	0	2,000	0	2,000
40	ESI Vansycle Partners, LP	LU	WSPP-1				59,974	0	0	0	0	4,775,438	0	4,775,438
41	Eugene Water & Electric Board	LU	WSPP-1				0	0	0	0	(51,600)	0	0	(51,600)
42	Eugene Water & Electric Board	SF	ER94-717				7,353	0	0	0	0	200,762	0	200,762
43	Evergreen Biomass	LU	201				50,307	0	0	0	0	5,025,334	0	5,025,334
44	Exelon Generation Co.	SF	WSPP-1				13,783	0	0	0	0	384,535	0	384,535
45	Falls Creek Hydro	LU	201				15,516	0	0	0	0	1,389,442	0	1,389,442
46	Finley BioEnergy, LLC	LU	201				28,226	0	0	0	0	1,130,497	0	1,130,497
47	Fort Rock Solar 1	LU	201				27,253	0	0	0	0	2,605,331	0	2,605,331
48	Fort Rock Solar 4	LU	201				26,352	0	0	0	0	2,327,924	0	2,327,924
49	Gridforce Energy Management - GRID	SF	201				12	0	0	0	0	587	0	587
50	Idaho Power Company	SF	NWPP				20,734	0	0	0	0	553,743	0	553,743
51	Lake Oswego Corporation	LU	201				76	0	0	0	0	164	0	164
52	Labish Solar	LU	WSPP-1				3,863	0	0	0	0	322,692	0	322,692
53	J Aron & Company	SF	EEI				404	0	0	0	0	23,180	0	23,180
54	Macquarie Cook Power	SF	201				27,607	0	0	0	0	1,443,607	0	1,443,607
55	Mercuria Energy America, LLC	SF	WSPP-1				62,738	0	0	0	0	5,979,660	0	5,979,660
56	Merrill Lynch Commodities	SF	WSPP-1				3,200	0	0	0	0	107,000	0	107,000
57	Milford Solar	LU	201				4,560	0	0	0	0	456	0	456
58	Middlefork Irrigation District	LU	201				15,502	0	0	0	0	417,271	0	417,271
59	Morgan Stanley Capital Group	SF	PGE-11				13,821	0	0	0	0	476,223	0	476,223
60	Montague Solar	LU	WSPP-1				314,923	0	0	0	0	13,374,780	0	13,374,780
61	Nevada Power Company	SF	WSPP-1				398	0	0	0	0	20,696	0	20,696
62	NorthWestern Corporation	SF	WSPP-1				12,111	0	0	0	0	395,503	0	395,503
63	Norwest Energy 14	LU	201				3,542	0	0	0	0	573,292	0	573,292
64	Obsidian Lakeview	LU	201				25,211	0	0	0	0	2,505,575	0	2,505,575
65	OE Solar 3, LLC	LU	201				26,743	0	0	0	0	2,323,115	0	2,323,115
66	Okanogan County PUD, Washington	LF [c]	WSPP-1				259,596	0	0	0	0	10,443,045	0	10,443,045
67	O'Neil Solar	LU	201				3,360	0	0	0	0	335,667	0	335,667
68	Outback Solar	LU	Outback				7,337	0	0	0	0	804,620	0	804,620

69	Pacific Northwest Generating Company	LU	PGNC				38,427	0	0	0	0	3,784,574	0	3,784,574
70	PacifiCorp	SF	PGE-11				14,187	0	0	0	0	517,976	0	517,976
71	Palmer Creek Solar	LU	201				3,022	0	0	0	0	301,602	0	301,602
72	Pika Solar	LU	201				3,861	0	0	0	0	187	0	187
73	PaTu Wind	LU	WSPP-1				28,581	0	0	0	0	2,707,152	0	2,707,152
74	Phillips 66 Energy Trading LLC	LU	201				24,236	0	0	0	0	968,592	0	968,592
75	Duus Solar (Alchemy)	LU	201				36,101	0	0	0	0	3,589,333	0	3,589,333
76	Portland, City of	LU	#2821				81,591	0	0	0	0	3,532,180	0	3,532,180
77	Powerex	SF	PGE-11				74,490	0	0	0	0	17,587,454	0	17,587,454
78	Grant County, PUD No. 2, Washington	LU	Wanapum				1,706,540	0	0	0	0	146,424,106	0	146,424,106
79	Grant County, PUD No. 2, Washington	SF	Priest Rapids				653,846	0	0	0	0	56,101,124	0	56,101,124
80	Greenpark Solar, LLC	LU	201				1,428	0	0	0	0	2,519	0	2,519
81	Guzman Energy LLC	SF	WSPP-1				8,845	0	0	0	0	440,110	0	440,110
82	City of Glendale	SF	WSPP-1				30	0	0	0	0	0	0	0
83	Puget Sound Energy	SF	WSPP-1				148,995	0	0	0	0	6,544,773	0	6,544,773
84	Rafael Solar	LU	201				3,820	0	0	0	0	379,980	0	379,980
85	Riley Solar	LU	201				25,566	0	0	0	0	2,434,989	0	2,434,989
86	Rainbow Energy Marketing Company	SF	WSPP-1				1,945	0	0	0	0	155,607	0	155,607
87	Rock Garden Solar	LU	201				25,554	0	0	0	0	2,472,458	0	2,472,458
88	Roseville, City of	SF	WSPP-1				3,556	0	0	0	0	2,379,467	0	2,379,467
89	Seattle City Light	SF	WSPP-1				42,780	0	0	0	0	1,857,963	0	1,857,963
90	Shell Energy	SF	WSPP-1				57,300	0	0	0	0	1,914,588	0	1,914,588
91	Sheep Solar	LU	201				3,713	0	0	0	0	362,688	0	362,688
92	Silverton Solar	LU	201				3,602	0	0	0	0	373,577	0	373,577
93	Sacramento Municipal Utility District	SF	WSPP-1				12,999	0	0	0	0	2,157,404	0	2,157,404
94	Snohomish County, PUD No. 1, Washington	SF	WSPP-1				26,785	0	0	0	0	1,579,181	0	1,579,181
95	SP Solar 1, LLC	LU	201				3,609	0	0	0	0	44,261	0	44,261
96	SP Solar 5, LLC	LU	201				3,858	0	0	0	0	370,323	0	370,323
97	SP Solar 6, LLC	LU	201				2,815	0	0	0	0	7,881	0	7,881
98	SP Solar 7, LLC	LU	201				2,969	0	0	0	0	384,225	0	384,225
99	SP Solar 8, LLC	LU	201				2,152	0	0	0	0	575,264	0	575,264
100	SSD Clackamas 1	LU	201				7,208	0	0	0	0	506	0	506
101	SSD Clackamas 4	LU	201				4,175	0	0	0	0	362,326	0	362,326
102	SSD Clackamas 7	LU	201				3,871	0	0	0	0	330,220	0	330,220
103	SSD Marion 1	LU	201				3,871	0	0	0	0	298,502	0	298,502
104	SSD Marion 3	LU	201				4,002	0	0	0	0	317,726	0	317,726
105	SSD Marion 5	LU	201				4,159	0	0	0	0	378,761	0	378,761
106	SSD Marion 6	LU	201				4,164	0	0	0	0	301,049	0	301,049
107	Steel Bridge	LU	201				3,339	0	0	0	0	24,952	0	24,952
108	Starvation Solar 1 LLC	LU	201				26,085	0	0	0	0	2,477,955	0	2,477,955
109	St Louis Solar	LU	201				3,969	0	0	0	0	395,523	0	395,523
110	Suluss Solar 35	LU	201				3,468	0	0	0	0	168,122	0	168,122
111	Suluss Solar 33	LU	201				4,469	0	0	0	0	126,446	0	126,446
112	Suluss Solar 22	LU	201				4,735	0	0	0	0	89,838	0	89,838
113	Suluss Solar 25	LU	201				3,289	0	0	0	0	127,301	0	127,301
114	Suluss Solar 28	LU	201				0	0	0	0	0	173,797	0	173,797
115	Suluss Solar 29	LU	201				3,757	0	0	0	0	122,400	0	122,400

116	Suluss Solar 17	LU	201				4,105	0	0	0	0	198,081	0	198,081
117	Suntex Solar	LU	201				26,280	0	0	0	0	2,515,323	0	2,515,323
118	West Hines Solar	LU	201				23,931	0	0	0	0	2,429,775	0	2,429,775
119	Tacoma, City of	SF	WSPP-1				65,235	0	0	0	0	3,865,682	0	3,865,682
120	Tenaska Power Services	SF	WSPP-1				0	0	0	0	0	13,325	0	13,325
121	The Energy Authority	SF	WSPP-1				39,134	0	0	0	0	1,631,342	0	1,631,342
122	Thomas Creek Solar	LU	201				3,926	0	0	0	0	327,889	0	327,889
123	Tickle Creek	LU	201				3,094	0	0	0	0	228,278	0	228,278
124	TransAlta Energy Marketing	SF	PGE-11				294,168	0	0	0	0	24,183,490	0	24,183,490
125	TransCanada Energy Marketing	SF	WSPP-1				188	0	0	0	0	6,840	0	6,840
126	Turlock Irrigation District	SF	WSPP-1				28,935	0	0	0	0	607,625	0	607,625
127	Vitol Inc.	SF	WSPP-1				14,315	0	0	0	0	706,777	0	706,777
128	Volcano Solar	LU	201				1,425	0	0	0	0	104,289	0	104,289
129	VON FAMILY LTD PARTNERSHIP	LU	201				(2)	0	0	0	0	9	0	9
130	Warm Springs Power Enterprises	SF	WSPP-1				0	0	0	0	0	0	0	0
131	Warm Springs Power Enterprises	LU	WSPP-1				663,300	0	0	0	0	37,204,103	0	37,204,103
132	Warm Springs Power Enterprises	LU	WSPP-1				0	0	0	0	0	0	0	0
133	Wheatride Solar	LU	WSPP-1				121,954	0	0	0	68,252	(548,391)	0	(480,139)
134	Wheatridge Wind II, LLC	LU	WSPP-1				615,334	0	0	0	0	28,106,797	0	28,106,797
135	Kale Patch Solar	LU	201				3,835	0	0	0	0	320,249	0	320,249
136	Drift Creek	LU	201				13,554	0	0	0	0	1,173,966	0	1,173,966
137	Yamhill Solar	LU	Yamhill				0	0	0	0	0	134,482	0	134,482
138	[a] Load Balance Energy	OS	OATT				146,980	0	0	0	0	0	0	0
139	SPI Solar	[d] OS	201				0	0	0	0	0	29,507	0	29,507
140	Salt River Project	[e] OS	201				1	0	0	0	0	46	0	46
141	Country Village Estates	[f] OS	201				0	0	0	0	0	42,344	0	42,344
142	Domaine Drouhin	[g] OS	201				90	0	0	0	0	1	0	1
143	Starbuck Properties	[h] OS	201				23	0	0	0	0	2	0	2
144	Solar Payment Option	[i] OS	215-217				17,261	0	0	0	0	6,440,839	0	6,440,839
145	Tualatin Valley Water Dist	[j] OS	201				137	0	0	0	0	5	0	5
146	Green Power						0	0	0	0	0	0	15,949,006 [k]	15,949,006
147	NVPC MONET QF Deferrals						0	0	0	0	0	0	[l] (104,244)	(104,244)
148	Margin on Electric Financials						0	0	0	0	0	0	(19,055,916) [m]	(19,055,916)
149	Pelton Round Butte Financing Lease 49.9%						0	0	0	0	0	0	[n] 6,000,000	6,000,000
150	Wheatridge Battery Lease						0	0	0	0	0	0	[o] 2,098,800	2,098,800
151	PCAM Deferrals	AD					0	0	0	0	0	0	(71,328,477) [p]	(71,328,477)
152	REC Retirement Expense						0	0	0	0	0	0	[q] 582,132	582,132
153	Carbon Allowance Expense						0	0	0	0	0	0	(4,593,927) [r]	(4,593,927)
154	Grant County, PUD No. 2, Washington	IF	Priest Rapids				0	0	0	0	90,322,982	0	0	90,322,982
15	TOTAL						13,893,153	0	0	0	130,993,409	819,318,971	(70,452,626)	879,859,754

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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: StatisticalClassificationCode

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

(j) Concept: StatisticalClassificationCode

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

(k) 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.

(l) Concept: OtherChargesOfPurchasedPower

2021 NVPC MONET QF Deferrals & Cure Payments

(m) Concept: OtherChargesOfPurchasedPower

Margin on electric financial transactions.

(n) Concept: OtherChargesOfPurchasedPower

Pelton Round Butte Financial Lease amortization and interest

(o) Concept: OtherChargesOfPurchasedPower

Wheatridge Battery Lease amortization.

(p) Concept: OtherChargesOfPurchasedPower

PCAM Deferrals

(q) Concept: OtherChargesOfPurchasedPower

Expense of annual REC retirement to meet RPS compliance.

(r) Concept: OtherChargesOfPurchasedPower

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

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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: Megawatt Hours Received (i)	TRANSFER OF ENERGY: Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS: 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	14,552	14,310	0	0	[as] 140,058	140,058
2	BPA Power Business Line	Bonneville Power Administration	Other TVI Pumps Total	OLF	72	BPAT.PGE	Various	0	6,531	6,422	0	0	[at] 36,408	36,408
3	BPA Power Business Line	Bonneville Power Administration	Canby PUD Total	OLF	72	BPAT.PGE	Various	0	202,594	199,221	0	0	[au] 452,696	452,696
4	BPA Power Business Line	Bonneville Power Administration	Columbia River PUD Total	OLF	72	BPAT.PGE	Various	0	190,748	187,572	0	0	[av] 18,138	18,138
5	Pacificorp West	PacifiCorp	Portland General Electric	OLF	Exchange	PACW.PGE	Various	0	3,510	3,353	0	0	[aw] 266,992	266,992
6	Avangrid Renewables, LLC	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various	179	112,394	112,394	157,539	[am] (288,647)	[ax] 71,261	(59,847)
7	Avangrid Renewables, LLC			[c] OS	11			0	0	0	0	86,159	0	86,159
8	BPA Power Business Line	Bonneville Power Administration	Portland General Electric	FNO	7	BPAT.PGE	Various Subs	173	87,404	87,404	151,522	[an] (310,146)	[ay] 68,872	(89,752)
9	BPA Power Business Line			[d] OS	11			0	0	0	0	80,843	0	80,843
10	Brookfield Renewable Energy Marketing US LLC	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various	100	71,820	71,820	88,583	[ao] (289,337)	[az] 39,811	(160,943)
11	Brookfield Renewable Energy Marketing US LLC			[e] OS	11			0	0	0	0	51,624	0	51,624
12	Calpine Energy Services	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various	2,801	1,957,992	1,957,992	2,465,269	[ap] (4,266,610)	[ba] 1,115,095	(686,246)
13	Calpine Energy Services			[f] OS	11			0	0	0	0	1,388,262	0	1,388,262
14	Constellation New Energy	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various	505	323,478	323,478	444,709	[aq] (676,026)	[bb] 201,044	(30,273)
15	Constellation New Energy			[g] OS	11			0	0	0	0	224,306	0	224,306
16	Shell Energy North America	Bonneville Power Administration	Oregon Direct Access	FNO	7	BPAT.PGE	Various	147	107,215	107,215	129,659	[ar] (110,225)	[bc] 58,522	77,956
17	Shell Energy North America			[h] OS	11			0	0	0	0	77,676	0	77,676
18	Altop Energy Trading LLC	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	1,999	1,999	0	0	[bd] 3,971	3,971
19	Altop Energy Trading LLC			[i] OS	11			0	0	0	0	1,333	0	1,333
20	Avista Corp	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	775	775	0	0	[be] 4,655	4,655
21	Avista Corp	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	239,824	239,824	0	0	[bf] 1,440,644	1,440,644
22	Avista Corp	California Independent System Operator	Bonneville Power Administration	[j] OS	8	Malin500	JohnDay	0	1,150	1,150	0	0	0	0
23	Avista Corp			[k] OS	11			0	0	0	0	123,446	0	123,446
24	Brookfield Renewable Trading and Marketing LP	Bonneville Power Administration	Portland General Electric	NF	8	BPAT.PGE	PGE	0	58	58	0	0	[bg] 96	96
25	Brookfield Renewable Trading and Marketing LP	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	765	765	0	0	[bh] 1,270	1,270

26	Brookfield Renewable Trading and Marketing LP			[l] OS	11			0	0	0	0	533	0	533
27	Conoco Phillips Inc.	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	0	0	0	0	0	0
28	Conoco Phillips Inc.	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	92	92	0	0	[bi] 848	848
29	Conoco Phillips Inc.	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	758	758	0	0	[bj] 6,988	6,988
30	Conoco Phillips Inc.			[m] OS	11			0	0	0	0	3,992	0	3,992
31	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	510,136	510,136	0	0	[bk] 1,709,232	1,709,232
32	Shell Energy North America	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	352,590	352,590	0	0	[bl] 1,181,367	1,181,367
33	Shell Energy North America	California Independent System Operator	Bonneville Power Administration	LFP	7	Malin500	JohnDay	0	0	0	0	0	0	0
34	Shell Energy North America	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	1,868	1,868	0	0	[bm] 3,778	3,778
35	Shell Energy North America	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	4,080	4,080	0	0	[bn] 8,253	8,253
36	Shell Energy North America	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	1,421	1,421	0	0	[bo] 2,874	2,874
37	Shell Energy North America	Balancing Authority of Northern California	Bonneville Power Administration	[n] OS	8	CaptainJack	JohnDay	0	172	172	0	0	0	0
38	Shell Energy North America	California Independent System Operator	Bonneville Power Administration	[o] OS	8	Malin500	JohnDay	0	220	220	0	0	0	0
39	Shell Energy North America			[p] OS	11			0	0	0	0	520,983	0	520,983
40	Dynasty Power Inc	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	0	0	0	0	0	0
41	Dynasty Power Inc	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	404	404	0	0	[bp] 9,870	9,870
42	Dynasty Power Inc			[q] OS	11			0	0	0	0	416	0	416
43	Constellation New Energy	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	653	653	0	0	[bq] 5,835	5,835
44	Constellation New Energy	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	15,633	15,633	0	0	[br] 139,688	139,688
45	Constellation New Energy	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	144	144	0	0	[bs] 515	515
46	Constellation New Energy	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	2,909	2,909	0	0	[bt] 10,414	10,414
47	Constellation New Energy			[r] OS	11			0	0	0	0	15,764	0	15,764
48	Mag Energy Solutions	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	1,650	1,650	0	0	[bu] 3,152	3,152
49	Mag Energy Solutions	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	404	404	0	0	[bv] 772	772
50	Mag Energy Solutions			[s] OS	11			0	0	0	0	1,112	0	1,112
51	Macquarie Energy LLC	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	833	833	0	0	[bw] 1,636	1,636
52	Macquarie Energy LLC			[t] OS	11			0	0	0	0	832	0	832
53	Mercuria Energy America, LLC			LFP	7			0	0	0	0	0	[bx] 240,883	240,883
54	Mercuria Energy America, LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	14	14	0	0	[by] 39	39
55	Mercuria Energy America, LLC	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	2,561	2,561	0	0	[bz] 7,091	7,091
56	Mercuria Energy America, LLC			[u] OS	11			0	0	0	0	33,367	0	33,367
57	MFT Energy US Power LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	150	150	0	0	[ca] 383	383
58	MFT Energy US Power LLC	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	6,097	6,097	0	0	[cb] 15,576	15,576
59	MFT Energy US Power LLC			[v] OS	11			0	0	0	0	4,839	0	4,839
60	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	13,677	13,677	0	0	[cc] 42,412	42,412
61	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	32,931	32,931	0	0	[cd] 102,118	102,118
62	Morgan Stanley Capital Group	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	0	0	0	0	0	0
63	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	607	607	0	0	[ce] 1,197	1,197
64	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	3,464	3,464	0	0	[cf] 6,834	6,834
65	Morgan Stanley Capital Group	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	0	0	0	0	0	0
66	Morgan Stanley Capital Group			[w] OS	11			0	0	0	0	28,738	0	28,738
67	Pacificorp West	Portland General Electric	Bonneville Power Administration	LFP	7	RoundButte	REDMOND	0	24,577	24,577	0	0	[cg] 197,057	197,057
68	Pacificorp West	Portland General Electric	Bonneville Power Administration	NF	8	RoundButte	REDMOND	0	2,827	2,827	0	0	[ch] 8,731	8,731

69	Pacificorp West			[x] OS	11			0	0	0	0	11,542	0	11,542
70	Avangrid Renewables, LLC	Balancing Authority of Northern California	Bonneville Power Administration	LFP	7	CaptainJack	JohnDay	0	3,142	3,142	0	0	[ci] 78,574	78,574
71	Avangrid Renewables, LLC	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	0	0	0	0	0	0
72	Avangrid Renewables, LLC	Bonneville Power Administration	Bonneville Power Administration	LFP	7	KFALLSGEN	JohnDay	0	1,375	1,375	0	0	[cj] 34,386	34,386
73	Avangrid Renewables, LLC	California Independent System Operator	Bonneville Power Administration	LFP	7	Malin500	JohnDay	0	22,783	22,783	0	0	[ck] 569,752	569,752
74	Avangrid Renewables, LLC	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	91	91	0	0	[cl] 165	165
75	Avangrid Renewables, LLC			[y] OS	11			0	0	0	0	71,573	0	71,573
76	Puget Sound Energy Marketing	Northwestern Montana	Bonneville Power Administration	NF	8	COLSTRIP	TOWNSEND	0	1	1	0	0	[cm] 2	2
77	Puget Sound Energy Marketing	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	250	250	0	0	[cn] 544	544
78	Puget Sound Energy Marketing	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	2,164	2,164	0	0	[co] 4,709	4,709
79	Puget Sound Energy Marketing			[z] OS	11			0	0	0	0	1,514	0	1,514
80	Powerex Inc.	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	5,352	5,352	0	0	[cp] 43,850	43,850
81	Powerex Inc.	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	492,104	492,104	0	0	[cq] 4,031,894	4,031,894
82	Powerex Inc.	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	19,826	19,826	0	0	[cr] 64,441	64,441
83	Powerex Inc.	California Independent System Operator	Bonneville Power Administration	[aa] OS	8	Malin500	JohnDay	0	2,033	2,033	0	0	0	0
84	Powerex Inc.			[ab] OS	11			0	0	0	0	248,387	0	248,387
85	Rainbow Energy Marketing Corp	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	1,167	1,167	0	0	[cs] 3,346	3,346
86	Rainbow Energy Marketing Corp	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	13,958	13,958	0	0	[ct] 40,017	40,017
87	Rainbow Energy Marketing Corp			[ac] OS	11			0	0	0	0	14,894	0	14,894
88	Seattle City Light	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	366	366	0	0	[cu] 26,205	26,205
89	Seattle City Light	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	182	182	0	0	[cv] 13,031	13,031
90	Seattle City Light	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	0	0	0	0	0	0
91	Seattle City Light			[ad] OS	11			0	0	0	0	353	0	353
92	Sacramento Municipal Utility Dist.	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	50	50	0	0	[cw] 100	100
93	Sacramento Municipal Utility Dist.	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	460	460	0	0	[cx] 918	918
94	Sacramento Municipal Utility Dist.			[ae] OS	11			0	0	0	0	389	0	389
95	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern California	LFP	7	JohnDay	CaptainJack	0	67,431	67,431	0	0	[cy] 70,746	70,746
96	The Energy Authority	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	Malin500	0	70,327	70,327	0	0	[cz] 73,784	73,784
97	The Energy Authority	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	8,623	8,623	0	0	[da] 22,522	22,522
98	The Energy Authority	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	977	977	0	0	[db] 2,552	2,552
99	The Energy Authority	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	21,587	21,587	0	0	[dc] 56,382	56,382
100	The Energy Authority	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	2,522	2,522	0	0	[dd] 6,587	6,587
101	The Energy Authority	Balancing Authority of Northern California	Bonneville Power Administration	[af] OS	8	CaptainJack	JohnDay	0	4	4	0	0	0	0
102	The Energy Authority	California Independent System Operator	Bonneville Power Administration	[ag] OS	8	Malin500	JohnDay	0	596	596	0	0	0	0
103	The Energy Authority			[ah] OS	11			0	0	0	0	160,306	0	160,306
104	Transalta Energy Marketing (US) Inc.	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	133	133	0	0	[de] 327	327
105	Transalta Energy Marketing (US) Inc.	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	0	0	0	0	0	0
106	Transalta Energy Marketing (US) Inc.	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	850	850	0	0	[df] 2,093	2,093
107	Transalta Energy Marketing (US) Inc.			[ai] OS	11			0	0	0	0	699	0	699
108	Turlock Irrigation Dist	Balancing Authority of Northern California	Bonneville Power Administration	NF	8	CaptainJack	JohnDay	0	45	45	0	0	[dg] 83	83
109	Turlock Irrigation Dist	Bonneville Power Administration	Balancing Authority of Northern California	NF	8	JohnDay	CaptainJack	0	30,457	30,457	0	0	[dh] 56,023	56,023
110	Turlock Irrigation Dist	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	162	162	0	0	[di] 298	298
111	Turlock Irrigation Dist			[aj] OS	11			0	0	0	0	16,224	0	16,224
112	Tacoma Power	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	1,480	1,480	0	0	[dj] 2,867	2,867

113	Tacoma Power	California Independent System Operator	Bonneville Power Administration	NF	8	Malin500	JohnDay	0	20	20	0	0	(dk) 39	39
114	Tacoma Power			(ak) OS	11			0	0	0	0	568	0	568
115	Vitol Inc	Bonneville Power Administration	California Independent System Operator	NF	8	JohnDay	Malin500	0	1,200	1,200	0	0	(dl) 1,985	1,985
116	Vitol Inc			(al) OS	11			0	0	0	0	634	0	634
117	Public Utility District No. 1 of Cowlitz County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH		0	0	0	0	(dm) 144,530	144,530
118	Public Utility District No. 1 of Franklin County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH		0	0	0	0	(dn) 144,530	144,530
119	Public Utility District No. 1 of Klickitat County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH		0	0	0	0	(do) 158,983	158,983
120	Public Utility District No. 1 of Lewis County	Bonneville Power Administration	California Independent System Operator	LFP	7	JohnDay	COBH		0	0	0	0	(dp) 158,983	158,983
121	(a) Deferral			OS									8,691,235	8,691,235
122	(b) Accrual			OS								892,108	350,930	1,243,038
35	TOTAL							3,905	5,075,399	5,068,342	3,437,281	(1,877,575)	22,484,489	24,044,195

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

Amortization of revenues previously 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

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(h) 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.

(i) 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.

(j) Concept: StatisticalClassificationCode

Represents non-billed redirected MWhs.

(k) 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.

(l) 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.

(m) 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.

(n) Concept: StatisticalClassificationCode

Represents non-billed redirected MWhs.

(o) Concept: StatisticalClassificationCode

Represents non-billed redirected MWhs.

(p) Concept: StatisticalClassificationCode

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(r) Concept: StatisticalClassificationCode

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(s) Concept: StatisticalClassificationCode

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(u) Concept: StatisticalClassificationCode

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(y) 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.

(z) Concept: StatisticalClassificationCode

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(aa) Concept: StatisticalClassificationCode

Represents non-billed redirected MWhs.

(ab) Concept: StatisticalClassificationCode

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(ag) Concept: StatisticalClassificationCode
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(ah) Concept: StatisticalClassificationCode
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(ak) Concept: StatisticalClassificationCode
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(al) 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.
(am) 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.
(an) 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.
(ao) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
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(ar) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
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(as) 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.
(at) 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.
(au) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(av) 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.
(aw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Pre-888 contract executed between PGE and PacifiCorp concerning the exchange of transmission services over agreed-upon facilities.
(ax) 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.
(ay) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(az) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(bc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(bd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
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(bs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

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(db) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(de) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(df) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dh) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(di) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dk) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(do) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Includes scheduling, system control and dispatch service.
(dp) 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: 04/11/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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41					
42					
43					
44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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			85,785,224			85,785,224
2	Bonneville Power Admin	OS	413,180	413,180			[(d)] 16,724,834	16,724,834
3	Bonneville Power Admin	SFP	59,679	59,679		2,442,441		2,442,441
4	Bonneville Power Admin	NF	72,748	72,748		1,045,125		1,045,125
5	Arizona Public Service	NF	1,353	1,353		8,232		8,232
6	Avista Corp	NF	16,632	16,632		150,755		150,755
7	ALBERTA ELECTRIC SYSTEM OPERATOR	NF	27,995	27,995		292,606		292,606
8	Columbia River PUD	SFP	7	7		19,256		19,256
9	Eugene Water & Electric Board	[(b)] LFP	5	5		114,840		114,840
10	Idaho Power Co	NF	12,381	12,381		79,075		79,075
11	LA Dept of Water & Power	NF	2,476	2,476		125,847		125,847
12	McMinnville Water & Light	[(c)] LFP	1,023	1,023		11,372		11,372
13	Montana, State of	OS					[(e)] 1,673,516	1,673,516
14	Nextera Energy Capital Holdings Inc	OS					[(f)] 6,555,737	6,555,737
15	Nevada Power Company	NF	8,774	8,774		53,186		53,186
16	NorthWestern Energy	NF	5,326,394	5,326,394		17,665,617		17,665,617
17	PacifiCorp	OS	261,067	261,067		(41,617)		(41,617)
18	PacifiCorp Linneman Substation	SFP					[(g)] 178,771	178,771
19	TRI-STATE GENERATION &TRANSMISSION	NF	1	1		480		480
20	Puget Sound Energy	NF	4,614	4,614		6,975		6,975
21	Okanogan County PUD, Washington	NF	202,572	202,572		279,988		279,988
22	WESTERN AREA POWER	NF	971	971		14,791		14,791
23	Salt River Project	NF	502	502		3,587		3,587
24	Seattle City Light	NF	15,451	15,451		27,039		27,039
25	Snohomish County	SFP	4,681	4,681		9,852		9,852
26	Tucson Electric Power	NF	150	150		833		833
27	Umatilla Electric Cooperative	OS					[(h)] 58,882	58,882
	TOTAL		6,432,656	6,432,656	85,785,224	22,310,280	25,191,740	133,287,244

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode
Represents Bonneville Power Administration PTP contracts that have termination dates that range from 12/31/2024 - 1/1/2030.
(b) Concept: StatisticalClassificationCode
Represents Eugene Water & Electric Board contract which terminates on 12/31/2028.
(c) Concept: StatisticalClassificationCode
Represents McMinnville Water & Light contract (no expiration date)
(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 reserve charges for Wheatridge II and gen-tie services for Clearwater.
(g) Concept: OtherChargesTransmissionOfElectricityByOthers
Represents PacifiCorp's Linneman Transmission Services.
(h) Concept: OtherChargesTransmissionOfElectricityByOthers
Represents 2024 Annual Capacity Payment.

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,938,102
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	3,408,592
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	2,688,532
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Involuntary Severance	2,634,899
7	Directors Pension	154,823
8	Directors and Officers Expenses	2,874,418
9	Misc Admin Expenses	296,883
10	Colstrip - PPL Montana	755,400
46	TOTAL	15,751,649

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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			79,219,629		79,219,629
2	Steam Production Plant	37,705,582	12,394,605			50,100,187
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	24,064,648	68			24,064,716
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	103,516,039	1,020,148			104,536,187
7	Transmission Plant	26,944,693				26,944,693
8	Distribution Plant	153,386,314	5,513			153,391,827
9	Regional Transmission and Market Operation					
10	General Plant	47,198,890	115			47,199,005
11	Common Plant-Electric					
12	TOTAL	392,816,166	13,420,449	79,219,629		485,456,244

B. Basis for Amortization Charges

Three year, 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	Depreciation parameters per Order 21-463 in OPUC Docket UM-2152. Rates effective as of 5/9/2022. Certain energy storage asset depreciation parameters per Order 18-290 in OPUC Docket UM-1856.						

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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 (b) + (c) (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	FERC Docket EL24-150		44,127	44,127				44,127				
3	FERC matters less than $25,0000		(11,641)	(11,641)				(11,641)				
4	OPUC:											
5	OPUC Docket UE 394		47,179	47,179				47,179				
6	OPUC Docket LC 80		172,675	172,675				172,675				
7	OPUC Docket UE 430		338,223	338,223				338,223				
8	OPUC Docket UE 435		174,533	174,533				174,533				
9	OPUC Docket UE 436		42,663	42,663				42,663				
10	OPUC regulatory commission expenses including annual fees and various dockets including: UE 427 Clearwater RAAC, UE 436 2025 Annual Power Cost Update Tariff, UE 435 Request for General Rate Revision, UE 412 Wildfire Mitigation Cost Recovery, UM 2024 Investigation into Long Term Direct Access Programs, UM 2208 Wildfire Mitigation Plan, UM 2211 Implementation of HB 2475		1,505,385	1,505,385				1,505,385				
11	OPUC matters less than $25,0000		112,441	112,441				112,441				
12	Unassigned Non-Doc Matters		783,423	783,423				783,423				
46	TOTAL	0	3,209,008	3,209,008	0			3,209,008	0		0	0

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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:

Electric R, D and D Performed Internally:

- Generation
  - hydroelectric
    - Recreation fish and wildlife
    - Other hydroelectric
  - Fossil-fuel steam
  - Internal combustion or gas turbine
  - Nuclear
  - Unconventional generation
  - Siting and heat rejection
- Transmission
  - Overhead
  - Underground
- Distribution
- Regional Transmission and Market Operation
- Environment (other than equipment)
- Other (Classify and include items in excess of $50,000.)
- Total Cost Incurred

Electric, R, D and D Performed Externally:

- Research Support to the electrical Research Council or the Electric Power Research Institute
- Research Support to Edison Electric Institute
- Research Support to Nuclear Power Groups
- Research Support to Others (Classify)
- 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: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	B(1)	Electric R, D & D Performed Externally	0	3,200,308	930.2	3,200,308	0
2	B(4)	Electric R, D & D Performed Externally	0	35,000	930.2	35,000	0

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	38,316,428		
4	Transmission	7,158,151		
5	Regional Market			
6	Distribution	22,282,869		
7	Customer Accounts	24,189,932		
8	Customer Service and Informational	9,934,404		
9	Sales			
10	Administrative and General	100,513,697		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	202,395,481		
12	Maintenance			
13	Production	11,291,480		
14	Transmission	1,356,324		
15	Regional Market			
16	Distribution	33,852,173		
17	Administrative and General	1,329,288		
18	TOTAL Maintenance (Total of lines 13 thru 17)	47,829,265		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	49,607,908		
21	Transmission (Enter Total of lines 4 and 14)	8,514,475		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	56,135,042		
24	Customer Accounts (Transcribe from line 7)	24,189,932		
25	Customer Service and Informational (Transcribe from line 8)	9,934,404		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	101,842,985		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	250,224,746	30,312,603	280,537,349
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)	250,224,746	30,312,603	280,537,349
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	74,577,005	62,597,098	137,174,103
69	Gas Plant			0
70	Other (provide details in footnote):			0
71	TOTAL Construction (Total of lines 68 thru 70)	74,577,005	62,597,098	137,174,103
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,361,931	103,015	1,464,946
74	Gas Plant			0
75	Other (provide details in footnote):			0
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,361,931	103,015	1,464,946
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	2,019,070	552,655	2,571,725
79	Co-Owner Shares of Generating Facilities	6,299,344	1,146,826	7,446,170
80	Other	9,282,144	16,642,657	25,924,801
81	Payroll Allocated	111,354,854	(111,354,854)	0
82				
83				
84				
85				

86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	128,955,412	(93,012,716)	35,942,696
96	TOTAL SALARIES AND WAGES	455,119,094	0	455,119,094

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

COMMON UTILITY PLANT AND EXPENSES

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

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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)	42,485,608	5,730,525	11,004,677	[(a)]64,384,035
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	24,341,586	15,504,296	4,906,606	[(b)]59,241,166
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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8					
9					
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45					
46	TOTAL	66,827,194	21,234,821	15,911,283	123,625,201

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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.

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	413,180	MWH	17,485,383	1,306,247	MWH	973,013
2	Reactive Supply and Voltage				7,217	MWH	156,604
3	Regulation and Frequency Response				3,905	MWH	339,872
4	Energy Imbalance	[a]156,911	MWH	[b]7,606,015	[c]48,391	MWH	[d]1,778,196
5	Operating Reserve - Spinning				[e]124,692	MW	392,160
6	Operating Reserve - Supplement				[f]124,692	MW	392,160
7	Other						
8	Total (Lines 1 thru 7)	570,091		25,091,398	1,615,144		4,032,005

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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. 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.

(b) Concept: AncillaryServicesPurchasedAmount

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. 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. 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.

(d) Concept: AncillaryServicesSoldAmount

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. 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: 04/11/2025	Year/Period of Report End of: 2024/ 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	January	5,337	13	10	3,580	248	2,561	90	3,832	143
2	February	4,686	8	18	2,769	278	2,561	66	3,202	27
3	March	4,389	6	8	3,169	274	2,561	80	3,148	197
4	Total for Quarter 1				9,518	800	7,683	236	10,182	367
5	April	4,061	4	21	2,643	252	2,561	69	3,102	250
6	May	4,028	11	18	2,696	299	2,561	63	4,419	204
7	June	4,503	25	20	3,035	333	2,561	64	4,021	307
8	Total for Quarter 2				8,374	884	7,683	196	11,542	761
9	July	5,815	8	19	3,947	367	2,561	97	4,442	99
10	August	5,405	1	18	3,920	394	2,561	74	4,211	706
11	September	5,491	5	16	3,615	386	2,561	69	4,288	394
12	Total for Quarter 3				11,482	1,147	7,683	240	12,941	1,199
13	October	4,705	23	20	2,523	313	2,561	48	3,602	483
14	November	4,783	4	19	2,668	319	2,561	59	3,202	282
15	December	5,374	10	14	2,865	332	2,561	82	3,202	168
16	Total for Quarter 4				8,056	964	7,683	189	10,006	933
17	Total				37,430	3,795	30,732	861	44,671	3,260

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

Monthly ISO/RTO Transmission System Peak Load

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

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

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-04-11	Year/Period of Report End of: 2024/ 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)	19,272,622
3	Steam	1,910,235	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear	0	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	10,305,039
5	Hydro-Conventional	1,266,720	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	27,222
7	Other	[a]13,873,009	27	Total Energy Losses	1,345,291
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	17,049,964	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	30,950,174
10	Purchases (other than for Energy Storage)	13,893,153			
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	5,075,399			
17	Delivered	5,068,342			
18	Net Transmission for Other (Line 16 minus line 17)	7,057			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	30,950,174			

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-04-11	Year/Period of Report End of: 2024/ 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 2,919,575 megawatt hours of net wind energy from PGE's Biglow Canyon Wind Farm, Tucannon River Wind Farm, Wheatridge Wind Farm and Clearwater Wind Farm. Actual gross wind generation from the wind farms was 2,927,392 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 12/31/2024: $980,951,982

Total installed capacity: 450 megawatts

Operations and maintenance expense for 2024: $17,971,140

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

In-service production cost at 12/31/2024: $501,953,535

Total installed capacity: 267 megawatts

Operations and maintenance expense for 2024: $9,894,745

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

In-service production cost at 12/31/2024: $154,737,264

Total installed capacity: 100 megawatts

Operations and maintenance expense for 2024: $5,413,596

The Clearwater Wind Farm was placed in service in January, 2024. Key statistics include the following:

In-service production cost at 12/31/2024: $413,558,542

Total installed capacity: 208 megawatts

Operations and maintenance expense for 2024: $4,605,210

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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					
29	January	2,780,312	795,244	3,969	16	18
30	February	2,462,530	774,088	3,323	14	19
31	March	2,443,609	734,193	3,428	6	8
32	April	2,269,569	722,424	2,932	5	8
33	May	2,256,365	674,797	3,020	11	19
34	June	2,367,028	853,425	3,445	21	18
35	July	2,987,007	1,154,416	4,367	9	19
36	August	3,105,426	1,367,073	4,322	1	19
37	September	2,803,649	1,210,540	4,066	5	18
38	October	2,344,133	778,241	3,020	30	19
39	November	2,492,087	777,762	3,340	18	18
40	December	2,638,459	676,726	3,570	2	18
41	Total	30,950,174	10,518,929			

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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 Mcf.
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: Plant Name: Beaver	Plant Name: Plant Name: Carty	Plant Name: [(a)] Plant Name: Colstrip	Plant Name: Plant Name: Coyote Springs	Plant Name: Plant Name: Port Westward 1	Plant Name: 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)	570.4	503.1	311.2	296	483.3	225.1
6	Net Peak Demand on Plant - MW (60 minutes)	484	487	0	284	426	214
7	Plant Hours Connected to Load	7,947	7,896	0	8,221	7,052	7,283
8	Net Continuous Plant Capability (Megawatts)	0	0	0	0	0	0
9	When Not Limited by Condenser Water	533	0	0	270	421	225
10	When Limited by Condenser Water	0	0	0	0	0	0
11	Average Number of Employees	41	33	0	32	33	0
12	Net Generation, Exclusive of Plant Use - kWh	1,719,576,000	3,292,884,000	1,910,235,000	2,031,823,000	2,748,931,000	1,146,008,000
13	Cost of Plant: Land and Land Rights	24,473	0	3,328,862	0	24,473	0
14	Structures and Improvements	38,118,883	95,908,445	116,250,719	11,772,629	43,220,414	42,471,958
15	Equipment Costs	317,951,959	437,105,965	382,722,350	195,360,282	256,583,247	277,074,793
16	Asset Retirement Costs	2,941,318	10,434,861	28,988,053	113,193	231,072	647,461
17	Total cost (total 13 thru 20)	359,036,633	543,449,271	531,289,984	207,246,104	300,059,206	320,194,212
18	Cost per KW of Installed Capacity (line 17/5) Including	629.4471	1,080.2013	1,707.23	700.1558	620.855	1,422.4532
19	Production Expenses: Oper, Supv, & Engr	430,922	331,740	(19,472)	272,425	546,543	230,803
20	Fuel	52,643,850	45,398,854	44,941,266	24,710,084	64,701,150	28,625,389
21	Coolants and Water (Nuclear Plants Only)	0	0	0	0	0	0
22	Steam Expenses	0	0	1,927,250	0	0	0
23	Steam From Other Sources	0	0	0	0	0	0
24	Steam Transferred (Cr)	0	0	0	0	0	0
25	Electric Expenses	4,382,929	2,295,449	0	2,903,476	3,280,355	2,368,809
26	Misc Steam (or Nuclear) Power Expenses	2,753,599	5,156,180	4,352,505	1,543,344	1,778,890	882,558
27	Rents	217,035	0	0	103,105	29,005	33,347
28	Allowances	0	0	0	0	0	0
29	Maintenance Supervision and Engineering	1,075,426	88,232	550,751	205,425	533,576	134,121
30	Maintenance of Structures	191,523	46,704	1,146,854	147,571	193,052	18,679
31	Maintenance of Boiler (or reactor) Plant	0	0	11,072,782	0	0	0
32	Maintenance of Electric Plant	4,941,905	8,761,693	1,808,495	3,593,727	10,877,141	5,752,762

33	Maintenance of Misc Steam (or Nuclear) Plant	683,135	174,733	665,313	132,546	403,702	206,794
34	Total Production Expenses	67,320,324	62,253,585	66,445,744	33,611,703	82,343,414	38,253,262
35	Expenses per Net kWh	0.0391	0.0189	0.0348	0.0165	0.03	0.0334

35	**Plant Name**	Plant Name: Beaver	Plant Name: Beaver	Plant Name: Carty	Plant Name: Coyote Springs	Plant Name: Port Westward 1	Plant Name: 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	17,493,260	23,715	22,315,458	14,420,594	18,975,663	9,651,844
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	3.306	0	1.154	1.175	2.884	2.898
41	Average Cost of Fuel per Unit Burned	2.868	0	2.034	1.714	3.41	2.966
42	Average Cost of Fuel Burned per Million BTU	2.814	0	1.995	1.681	3.345	2.91
43	Average Cost of Fuel Burned per kWh Net Gen	0.031	0	0.014	0.012	0.024	0.025
44	Average BTU per kWh Net Generation	(b)10,450.371	(c)0	6,908.128	7,234.829	7,036.62	8,585.264

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.

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	2023	1958	1931	1958	1958	1952	1964	1964	1953
5	Total installed cap (Gen name plate Rating in MW)	50	62.1	51	109.8	54.9	20.7	372.5	186.3	16.9
6	Net Peak Demand on Plant-Megawatts (60 minutes)	45	53	37	108	0	26	263	0	16
7	Plant Hours Connect to Load	8,784	8,618	8,113	8,726	0	8,606	8,595	0	8,556
8	**Net Plant Capability (in megawatts)**									
9	(a) Under Most Favorable Oper Conditions	46	56	42	114	0	25	373	0	18
10	(b) Under the Most Adverse Oper Conditions	5	7	19	60	0	4	192	0	7
11	Average Number of Employees	53	0	1	[(e)] 0	0	0	[(f)] 44	0	1
12	Net Generation, Exclusive of Plant Use - kWh	120,359,000	190,462,000	150,063,000	370,087,982	185,081,000	100,395,000	831,639,672	415,903,000	104,457,000
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	149,899,687.19	9,396,041	16,852,238	10,532,015	5,290,582	7,497,936	18,801,765	9,447,633	17,935,635
16	Reservoirs, Dams, and Waterways	63,708,799	86,076,883	32,450,814	15,511,814	8,016,063	58,516,049	174,956,291	89,982,599	31,499,172
17	Equipment Costs	45,809,234.81	21,166,030	31,281,250	37,505,601	19,134,276	19,228,526	44,646,768	171,972,181	16,674,960
18	Roads, Railroads, and Bridges	1,990,337	2,837,601	6,819,503	6,403,938	3,498,050	475,899	2,568,063	1,380,273	0
19	Asset Retirement Costs	90	6	2,122	52	52	64	164	164	2,630
20	Total cost (total 13 thru 20)	261,441,582	119,853,661	87,415,384	73,635,073	37,780,325	85,804,882	244,672,337	274,674,113	66,684,474
21	Cost per KW of Installed Capacity (line 20 / 5)	5,228.8316	1,930.0106	1,714.0271	670.6291	688.1662	4,145.1634	656.8385	1,474.3645	3,945.8269
22	**Production Expenses**									
23	Operation Supervision and Engineering	373,020	273,801	212,390	319,838	105,624	58,824	652,906	391,089	94,233
24	Water for Power	84,192	66,168	89,724	227,532	89,004	54,744	388,272	218,960	45,336
25	Hydraulic Expenses	1,691,357	1,038,023	1,635,737	2,830,084	1,465,303	373,448	3,243,474	1,575,408	284,886
26	Electric Expenses	938,202	215,501	69,368	452,887	240,076	4,921	493,132	233,030	31,552
27	Misc Hydraulic Power Generation Expenses	2,559,982	598,683	755,104	1,050,731	525,562	247,419	1,291,576	649,703	365,106
28	Rents	198,552	123,060	856,129	16,132	4,435	0	35,864	21,568	0
29	Maintenance Supervision and Engineering	490,437	503,798	34,392	10,801	6,504	53,610	8,300	3,048	0
30	Maintenance of Structures	0	0	2,051	0	0	0	0	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	56,465	64,882	1,172,764	114,435	29,564	56,338	262,849	159,118	316,287
32	Maintenance of Electric Plant	90,885	157,383	283,551	382,005	213,487	242,168	374,379	168,413	124,247
33	Maintenance of Misc Hydraulic Plant	1,099,072	455,128	198,633	227,458	101,901	1,115,360	337,900	184,441	50,060
34	Total Production Expenses (total 23 thru 33)	7,582,164	3,496,427	5,309,843	5,631,903	2,781,460	2,206,832	7,088,652	3,604,778	1,311,707

35	Expenses per net kWh	0.063	0.0184	0.0354	0.0152	0.015	0.022	0.0085	0.0087	0.0126

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: 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.
(f) 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.

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:
1	Type of Plant Construction (Conventional or Outdoor)				
2	Year Originally Constructed				
3	Year Last Unit was Installed				
4	Total installed cap (Gen name plate Rating in MW)				
5	Net Peak Demaind on Plant-Megawatts (60 minutes)				
6	Plant Hours Connect to Load While Generating				
7	Net Plant Capability (in megawatts)				
8	Average Number of Employees				
9	Generation, Exclusive of Plant Use - kWh				
10	Energy Used for Pumping				
11	Net Output for Load (line 9 - line 10) - Kwh				
12	**Cost of Plant**				
13	Land and Land Rights				
14	Structures and Improvements				
15	Reservoirs, Dams, and Waterways				
16	Water Wheels, Turbines, and Generators				
17	Accessory Electric Equipment				
18	Miscellaneous Powerplant Equipment				
19	Roads, Railroads, and Bridges				
20	Asset Retirement Costs				
21	Total cost (total 13 thru 20)				
22	Cost per KW of installed cap (line 21 / 4)				
23	**Production Expenses**				
24	Operation Supervision and Engineering				
25	Water for Power	648,128	648,128	648,128	648,128
26	Pumped Storage Expenses				
27	Electric Expenses				
28	Misc Pumped Storage Power generation Expenses				
29	Rents				
30	Maintenance Supervision and Engineering				
31	Maintenance of Structures				
32	Maintenance of Reservoirs, Dams, and Waterways				
33	Maintenance of Electric Plant				
34	Maintenance of Misc Pumped Storage Plant				
35	Production Exp Before Pumping Exp (24 thru 34)				
36	Pumping Expenses				

37	Total Production Exp (total 35 and 36)				
38	Expenses per kWh (line 37 / 9)				
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))				

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	Oregon Military Dept/Anderson Readiness Center	2001	1.6	1.6	26	192,125	120,078		21,730	24,833	diesel-low	2,019	Other
2	US Bank Corp Columbia Center	2001	6.4	6.2	83	488,057	76,259			120,923	diesel-low	1,960	Other
3	Portland State University	2004	2.8	2.8	23	261,802	93,501			26,468	diesel-low	1,960	Other
4	Oregon Military Joint Forces HQ	2005	1.6	1.6	23	1,648,371	1,030,232			48,913	diesel-low	1,960	Other
5	Stimson Lumber	2005	0.57	0.51	4	159,546	279,905		2,265	28,068	diesel-low	2,108	Other
6	Flexential (Formerly ViaWest/Fortix)	2005	14	12.4	127	6,347,476	453,391		23,711	217,391	diesel-low	1,534	Other
7	Skyline	2005	2	1.8	132	1,219,568	609,784		20,733	17,425	diesel-low	1,962	Other
8	NCCWC Filter Plant	2005	2	1.8	28	927,722	463,861		4,132	28,226	diesel-low	1,975	Other
9	PCC Structurals	2005	1	0.9	7	113,874	113,874		2,086	54,103	diesel-low	2,089	Other
10	Providence Portland Medical Center	2005	6	5.4	89	2,710,616	451,769		22,076	75,877	diesel-low	1,980	Other
11	Salem Hospital	2006	8	7.2	89	269,108	33,639			128,996	diesel-low	1,960	Other
12	Sunrise Water Authority Pump Station	2006	1.25	1.13	7	687,432	549,946			14,897	diesel-low	1,960	Other
13	Providence Newberg Hospital	2006	1.5	1.35	17	1,228,780	819,187			23,427	diesel-low	1,960	Other
14	H5 (Formerly vXchnge/Sungard DSG)	2006	2	1.8	12	331,845	165,923		2,945	23,405	diesel-low	1,992	Other
15	Kaiser Sunnyside Hospital	2007	4.5	4.05	86	2,363,292	525,176		63,045	80,495	diesel-low	2,156	Other
16	Newberg Waste Water Treatment Plant	2008	2	1.8	37	813,862	406,931		5,577	14,787	diesel-low	2,107	Other
17	Xerox Corp	2007	4	3.6	29	1,590,909	397,727		6,486	41,496	diesel-low	1,962	Other
18	Newberg Water Treatment Plant	2007	1	0.9	18	92,255	92,255		3,746	10,753	diesel-low	2,063	Other
19	Oregon Dept of Admin Serv - Data Center	2010	3.86	3.47	12	332,026	86,017		5,777	30,935	diesel-low	1,626	Other
20	Amazon (Formerly Panasonic/Sanyo)	2010	1	0.9	17	666,960	666,960		3,072	7,881	diesel-low	2,011	Other
21	Sysco Foods	2010	2	1.8	18	1,178,756	589,378			12,915	diesel-low	1,960	Other
22	Clackamas Intertie 2	2012	0.6	0.54	12	727,667	1,212,778		3,120	14,050	diesel-low	2,018	Other
23	DAW - Dawson Creek	2012	0.8	0.72		109,802	137,253			2,827	diesel-low		Other
24	Kaiser Westside Hospital	2012	4	3.6	53	408,830	102,208		21,228	54,119	diesel-low	1,905	Other

25	North Plains Pump Station	2012	0.8	0.72		67,227	84,034			3,118	diesel-low		Other
26	Oak Lodge Sanitary District	2012	2	1.8	26	1,314,329	657,165		10,389	12,834	diesel-low	2,025	Other
27	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.5	1.25	10	888,629	592,419		2,248	12,459	diesel-low	1,969	Other
28	Oregon State Hospital	2012	4	3.6	33	1,388,548	347,137			40,319	diesel-low	1,960	Other
29	Portland Service Center	2012	0.5	0.45	9	336,951	673,902			21,842	diesel-low	1,960	Other
30	Sandy Highschool	2012	1.25	1.13	14	949,944	759,955		3,899	25,410	diesel-low	1,869	Other
31	TATA Communications - Hillsboro	2012	4.5	4.05		328,979	73,106			4,701	diesel-low		Other
32	Tri-City Wastewater Treatment Plant	2012	2.5	2.25	45	175,790	70,316		8,801	17,875	diesel-low	1,957	Other
33	TATA Communications - Portland	2013	6	5.4		612,983	102,164			11,617	diesel-low		Other
34	CRAND - City of Hillsboro - Crandall Reservoir	2013	0.8	0.72	2	119,949	149,936			24,371	diesel-low	1,960	Other
35	East County Courts	2013	1.5	1.35	11	1,459,831	973,221		2,015	19,767	diesel-low	1,933	Other
36	City of Portland-Columbia Blvd WWTP	2013	1	0.9	11	176,330	176,330		2,749	11,168	diesel-low	2,081	Other
37	US Foods (Formerly Food Services of America)	2013	2	1.8	40	997,785	498,893		9,438	60,046	diesel-low	2,092	Other
38	Avery DSG	2014	0.8	0.72	17	263,782	329,728			8,901	diesel-low	1,960	Other
39	Carver (Readiness Center) DSG	2014	2	1.8	40	818,635	409,318		7,064	68,847	diesel-low	2,032	Other
40	Juvenile Justice Center	2014	0.75	0.68	19	794,825	1,059,767		774	15,007	diesel-low	2,071	Other
41	Clackamas River Water	2014	2	1.8	29	1,158,199	579,100		7,811	12,217	diesel-low	1,971	Other
42	Joint Water Commission	2015	5	4.5	32	204,398	40,880		9,723	55,027	diesel-low	1,888	Other
43	McLane Foodservice	2016	1.5	1.35	31	938,342	625,561		6,975	4,433	diesel-low	2,021	Other
44	Flexential Brookwood (Formerly ViaWest Brookwood)	2016	16.25	14.63	365	582,945	35,874			64,591	diesel-low	1,960	Other
45	World Trade Center	2017	3.2	2.88	27	1,021,168	319,115		6,151	99,400	diesel-low	2,010	Other
46	Washington County Jail	2017	1.5	1.35	12	1,478,397	985,598			3,520	diesel-low	1,960	Other
47	OHSU - Vaccine Gene Therapy Institute	2017	1.5	1.25		366,768	244,512			446	diesel-low		Other
48	OHSU - Center for Health & Healing	2018	3	2.7	28	351,605	117,202		10,271	95,769	diesel-low	1,961	Other
49	OHSU - Knight Cancer Research Building	2018	2	1.8	15	237,298	118,649		2,443	18,679	diesel-low	1,991	Other
50	Hattan Road Pump Station - HRPS	2021	1	0.9	1	212,306	212,306			6,310	diesel-low	1,960	Other
51	Beaverton Public Service Center	2021	1	0.9	6	523,446	523,446			11,819	diesel-low	1,960	Other
52	Kellogg Creek WWTP	2022	1.5	1.35	26	283,231	188,821		6,839	11,707	diesel-low	1,924	Other
53	Solar	2012	3.019	3.019	2,230	1,324,428	438,698	20,039		48,929	solar		Solar

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Account for Project Costs (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
1	Coffee Creek Energy Storage	[a] Distribution	Washington County, OR	651			651			67	573	57,258	29,131			$27,367,865			27,367,865
2	Constable Battery Energy Storage	[b] Distribution	Washington County, OR	1,532			1,532			26	1,348	137,388	46,876			$152,434,792			152,434,792
3																			
4																			
5																			
35	TOTAL			2,183	0	0	2,183	0	0	93	[c] 1,921	[d] 194,646	[e] 76,007	0	0		0	0	179,802,657

FOOTNOTE DATA

(a) Concept: FunctionalClassificationEnergyStorageOperationsLargePlants
As of December 31, 2024, PGE's batteries have been functionalized as Distribution based on the predominate use of the assets. It should be noted that beginning January 1, 2025, under FERC Order 898, these assets will be transferred to the newly created Battery Storage functional class. Although the predominate use and resulting functionalization is Distribution as of December 31, 2024, certain storage assets are expected to provide transmission functions in the future and may be functionalized as such for ratemaking purposes.
(b) Concept: FunctionalClassificationEnergyStorageOperationsLargePlants
As of December 31, 2024, PGE's batteries have been functionalized as Distribution based on the predominate use of the assets. It should be noted that beginning January 1, 2025, under FERC Order 898, these assets will be transferred to the newly created Battery Storage functional class. Although the predominate use and resulting functionalization is Distribution as of December 31, 2024, certain storage assets are expected to provide transmission functions in the future and may be functionalized as such for ratemaking purposes.
(c) Concept: EnergySold
PGE's large battery fleet is on-system. 88% of the discharge is assumed to meet system on peak needs (reported here) where the remaining 12% is assumed to be used for merchant ancillary services.
(d) Concept: RevenuesFromEnergyStorageOperations
PGE is unable to discern how much of the discharge for energy arbitrage was retail load serving versus sold to wholesale markets. As such, a weighted average method was used to develop total sales value for this page contemplating 2024 customer rates and wholesale MidC prices. The implied sales were recognized in FERC accounts: 447, 440, 442 and 444.
(e) Concept: PowerPurchasedForStorageOperationsLargePlants
PGE is unable to discern what transaction explicitly was used to charge its large on-system battery fleet. For this page, we assume it was charged using purchased power at the MidC day ahead off-peak price.

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1									
2									
3	Anderson Readiness Center	[(a)] Distribution	Marion County, OR	1,658,159	0	705	0	0	0
4	Beaverton Public Safety Center	[(b)] Distribution	Washington County, OR	1,308,628	0	10,200	0	0	0
5	Port Westward 2	Production	Columbia County, OR	6,332,259	0	73,881	0	0	0
36	TOTAL			9,299,046	0	84,786	0	0	0

FOOTNOTE DATA

(a) Concept: FunctionalClassificationEnergyStorageOperationsSmallPlants
As of December 31, 2024, PGE's batteries have been functionalized as Distribution based on the predominate use of the assets. It should be noted that beginning January 1, 2025, under FERC Order 898, these assets will be transferred to the newly created Battery Storage functional class. Although the predominate use and resulting functionalization is Distribution as of December 31, 2024, certain storage assets are expected to provide transmission functions in the future and may be functionalized as such for ratemaking purposes.
(b) Concept: FunctionalClassificationEnergyStorageOperationsSmallPlants
As of December 31, 2024, PGE's batteries have been functionalized as Distribution based on the predominate use of the assets. It should be noted that beginning January 1, 2025, under FERC Order 898, these assets will be transferred to the newly created Battery Storage functional class. Although the predominate use and resulting functionalization is Distribution as of December 31, 2024, certain storage assets are expected to provide transmission functions in the future and may be functionalized as such for ratemaking purposes.

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	500KV LINES											0				0
2	[a] BOARDMAN	GRASSLAND	500	500	ST. TOWER	0.94		1	2-1780 ACSR			0				0
3	[b] 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	86,639,716	88,166,326	2,585,807	506,111	2,364,813	5,456,731
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			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 ACSR			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	(g) CARTY	230	230	H-WOOD	16.76		1	795 AAC			0				0
31	EVERGREEN	HORIZON	230	230	Tubular Steel Pole	1.86		2	2156 ACSS			0				0
32	EVERGREEN	ST. MARYS-TROJAN	230	230	Steel Pole/Lattice Towers	14.03	32.6	2	1590 AAC			0				0
33	(l) GRESHAM	TROUTDALE PACW #1	230	230	H-WOOD	0.43		1	954 ACSR			0				0
34	GRESHAM	TROUTDALE PACW #2	230	230	ST. TOWER	0.33		1	1272 AAC			0				0
35	HARBORTON	RIVERGATE #1	230	230	ST. TOWER/H-WOOD	1.7		1	1272 AAC			0				0
36	HARBORTON	TROJAN #1	230	230	ST TOWER	33.6		2	1590 AAC			0				0
37	HORIZON	KEELER BPA#1	230	230	ST. MONOP	1.47		2	1272 ACSS			0				0
38	HORIZON	KEELER BPA#2	230	230	ST. MONOP	1.79		2	2156 ACSS			0				0
39	(m) KEELER BPA	RIVERGATE	230	230	ST. TOWER	0.08		2	1272 AAC			0				0
40	KEELER BPA	ST. MARYS	230	230	H-WOOD/ST. TOWER	6.62		2	1926 ACSR TW			0				0
41	McLOUGHLIN	PEARL BPA - SHERWOOD	230	230	ST. TOWER/ST. MONOP	16.38	4.7	2	1272 AAC			0				0
42	MURRAYHILL	SHERWOOD #1	230	230	ST. TOWER	5.58		2	1272 AAC			0				0
43	MURRAYHILL	SHERWOOD #2	230	230	ST. TOWER		5.55	2	1272 AAC			0				0
44	MURRAYHILL	ST. MARYS	230	230	ST. TOWER	5.2		2	1272 ACSS			0				0
45	(n) PEARL BPA	SHERWOOD	230	230	ST. MONOP/ST. TOWER/H-WOOD	4.88		1	2-2388 AAC TW			0				0
46	(o) PELTON	ROUND BUTTE	230	230	H-WOOD	7.87		1	795 ACSR			0				0
47	PORT WESTWARD	TROJAN #1	230	230	H-WOOD/ST. MONOP	18.76		1	2156 ACSS			0				0
48	PORT WESTWARD	TROJAN #2	230	230	H-WOOD/ST. MONOP	9.28	9.48	2	2156 ACSS			0				0
49	REDMOND BPA	ROUND BUTTE	230	230	H-WOOD	23.81		1	795 ACSR			0				0
50	(p) RIVERGATE	ROSS BPA	230	230	ST. TOWER	0.09		2	795 ACSR			0				0
51	ROUND BUTTE	GENERATOR #1	230	230	ST. TOWER			1	795 ACSR			0				0
52	ROUND BUTTE	GENERATOR #2	230	230	ST. TOWER			1	795 ACSR			0				0
53	ROUND BUTTE	GENERATOR #3	230	230	ST. TOWER			1	795 ACSR			0				0
54	TOTAL 230KV LINES									8,602,221	194,335,076	202,937,297	2,588,875	1,017,881	966,655	4,573,411
55	ALL 115KV LINES					443.15						0				0
56	ALL 57KV LINES					11.81						0				0
57	TOTAL 115KV & 57KV LINES									1,309,175	287,421,659	288,730,834	2,463,081	5,556,703		8,019,784
36	TOTAL					1,526.73	53.67	65		11,438,006	568,396,451	579,834,457	7,637,763	7,080,695	3,331,468	18,049,926

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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: 04/11/2025	Year/Period of Report End of: 2024/ 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			SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS				LINE COST					
	From (a)	To (b)	Line Length in Miles (c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)	Size (h)	Specification (i)	Configuration and Spacing (j)	Voltage KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	Construction (q)
1	Evergreen	Horizon	1.86	Tubular Steel Pole	19	2	2	2156 ACSS			230	0	6,706,185	5,269,147		11,975,332	
2	Evergreen	St Marys-Trojan	14.03	Steel Pole/Lattice Towers	17	1	2	1590 AAC			230	0	7,027,510	5,521,616		12,549,126	
3	Horizon	Keeler BPA #2	1.79	ST. MONOP	13	2	2	2156 ACSS			230	60,770	8,570,124	4,502,596		13,133,490	
4	Constable	Evergreen	0.19	Tubular Steel Pole	1	1	1	795 ACSS			115	0	136,542	173,779		310,321	
5	Evergreen	Helvetia	2.85	Wood Poles	1	1	1	795 ACSS			115	0	160,432	126,054		286,486	
6	Evergreen	Rock Creek	4.25	Tubular Steel Pole	5	1	1	795 AAC			115	0	327,048	256,967		584,015	
7	Evergreen	Shute #1	0.38	Steel/Wood Poles	7	1	1	2156 ACSS			115	0	1,318,989	1,036,350		2,355,339	
8	Evergreen	Shute #2	0.38	Steel/Wood Poles	7	1	1	2156 ACSS			115	0	28,677	22,532		51,209	
9	Evergreen	Sunset	2.02	Tubular Steel Pole	6	1	1	795 ACSS			115	0	1,721,886	1,352,912		3,074,798	
44	TOTAL		27.75		76	11	12					60,770	25,997,393	18,261,953	0	44,320,116	

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
1	2 Substation Under 10 MVA capacity	Distribution	Unattended	115	13		16.8	2		Capacitor Banks	2	3.6
2	6 Substation Under 10 MVA capacity	Distribution	Unattended	57	13		44.3	6				
3	Abernethy, Oregon City, OR	Distribution	Unattended	115	13		44.8	2		Capacitor Banks	4	12
4	Alder, Portland, OR	[(af)] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
5	Amity, near Amity, OR	Distribution	Unattended	57	13		16.875	2				
6	Arleta, Portland, OR	Distribution	Unattended	57	13		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		20	1		Capacitor Banks	2	3
9	Barnes, Salem, OR	Distribution	Unattended	115	13		42.4	2		Capacitor Banks	2	6
10	Beaver Plant, near Clatskanie, OR	Transmission	Unattended	230	13		464	4				
11	Beaver Plant, near Clatskanie, OR	Transmission	Unattended	230	24		170	1				
12	Beaverton, Beaverton, OR	[(ag)] Transmission	Unattended	115	13		33.6	2		Capacitor Banks	4	12
13	Bell, near Portland, OR	[(ah)] Transmission	Unattended	115	13		65.8	3		Capacitor Banks	6	18
14	Bethany, Portland, OR	[(ai)] Transmission	Unattended	115	13		56	2		Capacitor Banks	5	15
15	Bethel, Salem, OR	[(aj)] Transmission	Unattended	230	115	13	642	3				
16	Bethel, Salem, OR	[(ak)] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
17	Biglow Canyon Windfarm	Transmission	Unattended	230	34.5	13	480	3				
18	Blue Lake, Troutdale, OR	[(al)] Transmission	Unattended	230	115	13	640	2				
19	Blue Lake, Troutdale, OR	[(am)] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
20	[(b)] Blueridge, Lexington, Oregon	Transmission	Unattended	230	35		385	2				
21	Boones Ferry, Lake Oswego, OR	[(an)] Transmission	Unattended	115	13		50	2		Capacitor Banks	2	7.2
22	Boring, near Boring, OR	Distribution	Unattended	57	13		16.8	1	1	Capacitor Banks	1	12.15
23	[(c)] Broadview Subst. near Broadview, MT	Transmission	Unattended	500	230		80	3				
24	Brookwood, near Hillsboro, OR	[(ao)] Transmission	Unattended	115	13		100	2		Capacitor Banks	4	12
25	[(d)] Buckley, BPA near Buckley, WA	Transmission	Unattended	500								
26	Butler, Hillsboro OR	[(ap)] Transmission	Unattended	115	13		300	2	1	Capacitor Banks	2	48
27	Canby, near Barlow, OR	Distribution	Unattended	57	13		39.3	4				
28	Canemah, Oregon City, OR	[(aq)] Transmission	Unattended	115	57	13	264.8	4	2			
29	Canyon, Portland, OR	[(ar)] Transmission	Unattended	115	13		200	4		Capacitor Banks	8	28.8

30	[e] Captain Jack, BPA, Near Malin, OR	Transmission	Unattended	500								
31	Carty, near Boardman, OR	Transmission	Unattended	500	230	24	1170.5	4				
32	Carty, near Boardman, OR	Transmission	Unattended	230	7.2		55	1				
33	Carver, Carver, OR	[as] Transmission	Unattended	230	115	13	640	2				
34	Carver, Carver, OR	[at] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
35	Cascade, St Helens, OR	Distribution	Unattended	115	13		46.4	2	1	Capacitor Banks	4	12
36	Cedar Hills, near Beaverton, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	4	13.2
37	Centennial, near Gresham, OR	Distribution	Unattended	115	13		39.2	2		Capacitor Banks	2	7.2
38	[f] Chemawa BPA, near Salem, OR	Distribution	Unattended	115								
39	[g] Chemawa BPA, near Salem, OR	Distribution	Unattended	57								
40	Clackamas, Clackamas, OR	[au] Transmission	Unattended	115	13		43	2		Capacitor Banks	4	13.2
41	Claxtar, Salem,OR	Distribution	Unattended	57	13		28	1		Capacitor Banks	2	6
42	[h] Clearwater East, Custer County, MT	Transmission	Unattended	345	34.5	13.8	233	1				
43	Coffee Creek, Sherwood, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6
44	[i] Colstrip Plant, near Colstrip, MT	Transmission	Unattended	500	26		164	3				
45	[j] Colstrip Subst. near Colstrip, MT	Transmission	Unattended	500	230		100	2				
46	Cornelius, Cornelius, OR	[av] Transmission	Unattended	57	13		28	1		Capacitor Banks	2	6
47	Cornelius, Cornelius, OR	[aw] Transmission	Unattended	115	57	13	140	1	1			
48	Cornell, Portland, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6
49	[k] Coyote Springs, Boardman, OR	Transmission	Unattended	500			300	3				
50	Culver, Salem, OR	[ax] Transmission	Unattended	115	13		28	1				
51	Curtis, Portland, OR	[ay] Transmission	Unattended	115	13		16.8	1		Capacitor Banks	2	6
52	Dayton, near Dayton , OR	[az] Transmission	Unattended	57	13		19.5	2		Capacitor Banks	4	6
53	Dayton, near Dayton , OR	[ba] Transmission	Unattended	115	57	13	125	1				
54	Delaware, Portland, OR	[bb] Transmission	Unattended	115	13		28	1				
55	Denny, Beaverton, OR	[bc] Transmission	Unattended	115	13		56	2		Capacitor Banks	2	6
56	Dilley, near Forest Grove, OR	Distribution	Unattended	57	13		12.5	1		Capacitor Banks	3	9
57	Dunns Corner, near Sandy,OR	[bd] Transmission	Unattended	57	13		14	1		Capacitor Banks	2	3
58	Durham, Tigard , OR	Distribution	Unattended	115	13		77	4		Capacitor Banks	4	12.6
59	E., Portland, OR	[be] Transmission	Unattended	115	13		202.4	5		Capacitor Banks	3	21.6
60	E., Portland, OR	[bf] Transmission	Unattended	115	11		132.4	4		Capacitor Banks	1	24
61	E., Portland, OR	[bg] Transmission	Unattended	13	11		70	1		Capacitor Banks	1	7.2
62	E., Portland, OR	[bh] Transmission	Unattended	11			6	1		Capacitor Banks	1	8.4
63	Eagle Creek, Eagle Creek, OR	Distribution	Unattended	57	13		14	1				
64	Eastport, Portland, OR	[bi] Transmission	Unattended	115	13		16.8	1		Capacitor Banks	2	6
65	Elma, near Salem, OR	Distribution	Unattended	57	13		56	2		Capacitor Banks	4	12
66	Estacada, Estacada, OR	Distribution	Unattended	57	13		29.6	2		Capacitor Banks	2	3.6
67	Evergreen, Hillsboro, OR	Transmission	Unattended	230	115	13	640	2	2	Capacitor Banks	2	48
68	Evergreen, Hillsboro, OR	Transmission	Unattended	115	34.5							
69	Fairmount, Salem, OR	[bj] Transmission	Unattended	115	13		25	1		Capacitor Banks	1	3.6
70	Fairview, Fairview, OR	[bk] Transmission	Unattended	115	13		50.4	2		Capacitor Banks	1	3

71	Faraday, Switchyard, OR	[bl] Transmission	Unattended	115	57	13	140	1				
72	Faraday, Switchyard, OR	[bm] Transmission	Unattended	115	13		50	1				
73	Faraday, Switchyard, OR	[bn] Transmission	Unattended	57	11		32	2				
74	[l] Forest Grove BPA, Forest Grove, OR	Transmission	Unattended	115								
75	[m] Fort Rock, 12 mi NE of Silver Lake, OR	Transmission	Unattended	500						Series Capacitor	1	363
76	Garden Home, near Portland, OR	Distribution	Unattended	115	13		28	1				
77	Glencoe, Portland, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6
78	Glencullen, Portland, OR	[bo] Transmission	Unattended	115	13		24	1		Capacitor Banks	2	6
79	Glendoveer, near Portland, OR	[bp] Transmission	Unattended	115	13		50.4	2				
80	Glisan, Gresham, OR	[bq] Transmission	Unattended	115	13		44.8	2		Capacitor Banks	4	12
81	Grand Ronde, Grand Ronde, OR	[br] Transmission	Unattended	115	57	13	33	1	1			
82	Grand Ronde, Grand Ronde, OR	[bs] Transmission	Unattended	115	13		12.5	1		Capacitor Banks	2	3
83	Grassland, near Boardman, OR	Transmission	Unattended	500								
84	Gresham, near Gresham, OR	Transmission	Unattended	230	115	13	572	2				
85	[n] Grizzly, BPA, near Madras, OR	Transmission	Unattended	500								
86	Harborton, near Portland, OR	[bt] Transmission	Unattended	230	115	13	320	1		Capacitor Banks	1	24
87	Harborton, near Portland, OR	[bu] Transmission	Unattended	115	13		50	2		Capacitor Banks	4	12
88	Harmony, near Milwaukie, OR	Distribution	Unattended	115	13		50.4	2		Capacitor Banks	4	12
89	Harrison Sub, Portland, OR	[bv] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
90	Hayden Island, near Portland, OR	Distribution	Unattended	115	13		33.6	2		Capacitor Banks	4	12
91	Helvetia, Hillsboro, OR	[bw] Transmission	Unattended	115	34.5		200	4		Capacitor Banks	8	36
92	Hemlock, Portland, Or	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6
93	Hillcrest, Salem , OR	[bx] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
94	Hillsboro, Hillsboro , OR	Distribution	Unattended	57	13		43.4	2		Capacitor Banks	4	14.4
95	Hogan North, Gresham, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	4	12
96	Hogan South, Gresham, OR	[by] Transmission	Unattended	115	57	13	125	3				
97	Hogan South, Gresham, OR	[bz] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
98	Holgate, Portland, OR	Distribution	Unattended	57	13		39.2	2		Capacitor Banks	2	7.2
99	Horizon, Hillsboro, OR	Transmission	Unattended	230	115	13	960	3				
100	Huber, near Beaverton, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	2	6
101	Indian, near Salem, OR	[ca] Transmission	Unattended	115	13		56	2		Capacitor Banks	3	10.8
102	Island, near Milwaukie, OR	[cb] Transmission	Unattended	115	13		44.8	2		Capacitor Banks	4	12
103	Jennings Lodge, Jennings Lodge, OR	Distribution	Unattended	115	13		52.5	2				
104	[o] Keeler, BPA, Hillsboro, OR	Transmission	Unattended									
105	Kelley Point, Portland, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	4	12
106	Kelly Butte, Portland, OR	[cc] Transmission	Unattended	115	13		44.8	2		Capacitor Banks	2	6
107	King City, near King City, OR	[cd] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
108	Leland, Oregon City, OR	Distribution	Unattended	57	13		28	1		Capacitor Banks	2	6
109	Lents, near Portland, OR	Distribution	Unattended	115	13		22.4	1				
110	Lents, near Portland, OR	Distribution	Unattended	57	11		20	2				
111	Liberal	Distribution	Unattended	115	13		14	1		Capacitor Banks	1	12
112	Liberty, Salem, OR	[ce] Transmission	Unattended	115	13		50.4	2		Capacitor Banks	3	10.2

113	Main, Hillsboro, OR	Distribution	Unattended	57	13		84	3		Capacitor Banks	6	20.4
114	[p] Malin, BPA, near Malin, OR	Transmission	Unattended	500						Reactors	3	180
115	Market, Salem, OR	[cf] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
116	Marquam, Portland OR	[cg] Transmission	Unattended	115	13		250	5		Capacitor Banks	10	54
117	McClain, Salem, OR	Distribution	Unattended	57	13		22.5	3				
118	McGill, Gresham, OR	[ch] Transmission	Unattended	115	13		75.4	3	2	Capacitor Banks	6	18
119	McLoughlin, near Oregon City, OR	[ci] Transmission	Unattended	230	115	13	640	2				
120	Meridian, near Tualatin, OR	[cj] Transmission	Unattended	115	13		84	3		Capacitor Banks	6	18
121	Middle Grove, near Middle Grove, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	4	12
122	Midway, near Portland, OR	Distribution	Unattended	115	13		33.6	2		Capacitor Banks	1	3.6
123	Mill Creek, near Salem, OR	[ck] Transmission	Unattended	115	13		16.8	1		Capacitor Banks	2	6
124	Mobile No. 1, OR	Distribution	Unattended	115	57	13	25	1				
125	Mobile No. 2, OR	Distribution	Unattended	115	57	13	34	1				
126	Mobile No. 3, OR	Distribution	Unattended	115	57	13	29	1				
127	Mobile No. 4, OR	Distribution	Unattended	115	57	13	34	1				
128	Mobile No. 5, OR	Distribution	Unattended	115	57	13	34	1				
129	Mobile No. 6, OR	Distribution	Unattended	115	57	13	34	1				
130	Mobile No. 7, OR	Distribution	Unattended	115	57	13	25	1				
131	Mobile No. 8, OR	Distribution	Unattended	115	57	13	25	1				
132	Molalla, Molalla, OR	Distribution	Unattended	57	13		42.4	2		Capacitor Banks	4	9
133	Monitor, near Monitor, OR	[cl] Transmission	Unattended	230	57	13	125	1	2			
134	Mt. Angel, Mt. Angel, OR	Distribution	Unattended	57	13		20	1		Capacitor Banks	3	15
135	Mt. Pleasant, Oregon City , OR	Distribution	Unattended	115	13		44.8	2		Capacitor Banks		
136	Multnomah, Portland, OR	Distribution	Unattended	115	13		39.2	2		Capacitor Banks	3	9
137	Murrayhill, Beaverton, OR	[cm] Transmission	Unattended	115	13		56	2		Capacitor Banks	3	10.8
138	Murrayhill, Beaverton, OR	[cn] Transmission	Unattended	230	115	13	320	1				
139	Newberg, Newberg, OR	[co] Transmission	Unattended	115	13		44.8	2		Capacitor Banks	4	12
140	North Fork, near Estacada, OR	Transmission	Unattended	115	13	0.48	53	3				
141	North Marion, near Woodburn, OR	Distribution	Unattended	57	13		30.875	3		Capacitor Banks	3	15
142	North Plains, North Plains, OR	Distribution	Unattended	57	13		20	1		Capacitor Banks	4	16.5
143	Northern, Portland, OR	[cp] Transmission	Unattended	115	13		28	1				
144	Oak Grove, Three Lynx, OR	[cq] Transmission	Unattended	115	13		8	1				
145	Oak Grove, Three Lynx, OR	[cr] Transmission	Unattended	115	11		64	2				
146	Oak Grove, Three Lynx, OR	[cs] Transmission	Unattended	13	11							
147	Oak Grove, Three Lynx, OR	[ct] Transmission	Unattended	13	0.48							
148	Oak Hills, near Beaverton, OR	Distribution	Unattended	115	13		44.8	2		Capacitor Banks	4	14.4
149	[q] Oregon City - BPA, Wilsonville, OR	Distribution	Unattended	57								
150	Orenco, near Hillsboro, OR	[cu] Transmission	Unattended	115	57	13	280	2	1			
151	Orenco, near Hillsboro, OR	[cv] Transmission	Unattended	115	13		84	3		Capacitor Banks	6	18
152	Orient, near Gresham, OR	Distribution	Unattended	57	13		28	1		Capacitor Banks	2	6
153	Oswego, Lake Oswego, OR	[cw] Transmission	Unattended	115	13		33.6	2		Capacitor Banks	2	7.2
154	Oxford, Salem, OR	[cx] Transmission	Unattended	115	13		50.4	2		Capacitor Banks	4	12.3

155	[r] Pearl, BPA, near Wilsonville, OR	Transmission	Unattended	230								
156	[s] Pelton, near Madras , OR	Transmission	Unattended	230	13		120	3				
157	[t] Pelton, near Madras, OR	Transmission	Unattended	13	13		3	1				
158	Peninsula Park, Portland, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6
159	Pleasant Valley, near Portland, OR	[cy] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
160	Port Westward, near Clatskanie, OR	Transmission	Unattended	230	18		900	3				
161	Port Westward, near Clatskanie, OR	Transmission	Unattended	13	4.2		40	2				
162	Portsmouth, Portland, OR	[cz] Transmission	Unattended	115	13		28	1				
163	Progress, near Tigard, OR	[da] Transmission	Unattended	115	13		50	2		Capacitor Banks	4	13.8
164	Raleigh Hills, near Portland, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6.6
165	Ramapo, near Portland, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6
166	Redland, near Oregon City, OR	Distribution	Unattended	115	13		22.4	1				
167	Reedville, near Beaverton, OR	[db] Transmission	Unattended	115	13		84	3	3	Capacitor Banks	6	20.4
168	[u] Rhododendron Switching, OR	Distribution	Unattended	57								
169	River Mill, near Estacada, OR	[dc] Transmission	Unattended	57	11		32	2				
170	Rivergate North Yard, Portland, OR	[dd] Transmission	Unattended	230	115	13	520	4	1	Capacitor Banks	1	24
171	Rivergate South Yard, Portland, OR	Distribution	Unattended	115	13		22.4	1		Capacitor Banks	2	7.2
172	Rivergate South Yard, Portland, OR	Distribution	Unattended	115	11.4		22.4	1		Capacitor Banks	2	6.716
173	Riverview, Portland, OR	Distribution	Unattended	115	13		28	1		Capacitor Banks	2	6
174	Rock Creek, near Portland, OR	[de] Transmission	Unattended	115	113		28	1		Capacitor Banks	2	6
175	Rockwood, near Gresham, OR	Distribution	Unattended	115	13		78.4	3		Capacitor Banks	5	15
176	Rosemont, near Lake Oswego, OR	[df] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
177	Roseway, Hillsboro, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	4	12
178	[v] Round Butte, near Madras, OR	[dg] Transmission	Unattended	500	230	13	570	4		Reactors	4	60
179	[w] Round Butte, near Madras, OR	[dh] Transmission	Unattended	230	13		394	4				
180	Ruby, Gresham, OR	[di] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
181	Salem-PGE, near Salem, OR	Distribution	Unattended	57	13		44.8	2		Capacitor Banks	4	12
182	[x] Sand Springs, South of Bend, OR	Transmission	Unattended	500						Series Capacitor	1	546
183	Sandy, Sandy, OR	Distribution	Unattended	57	13		28	1		Capacitor Banks	2	6
184	[y] Scappoose, Scappoose, OR	[dj] Transmission	Unattended	115								
185	Scholls Ferry, Beaverton, OR	[dk] Transmission	Unattended	115	13		28	1	1	Capacitor Banks	2	6
186	Scoggins, near Gaston, OR	Distribution	Unattended	57	13		13	2		Capacitor Banks	1	10.8
187	Sellwood, Portland, OR	[dl] Transmission	Unattended	115	57	13	140	1		Capacitor Banks	1	24
188	Sellwood, Portland, OR	[dm] Transmission	Unattended	115	13		28	1		Capacitor Banks	2	6
189	Sheridan, Sheridan, OR	Distribution	Unattended	57	13		16.8	1		Capacitor Banks	3	15.6
190	Sherwood, near Six Corners, OR	Transmission	Unattended	230	115	13	640	2				
191	Shute, Hillsboro, OR	[dn] Transmission	Unattended	115	34.5		600	4		Capacitor Banks	8	36
192	Silverton, Silverton, OR	Distribution	Unattended	57	13		42	2				
193	Six Corners, Six Corners, OR	[do] Transmission	Unattended	115	13		49	2		Capacitor Banks	4	12
194	[z] Slatt, BPA, Arlington, OR	Transmission	Unattended	500								
195	Springbrook, Newberg, OR	[dp] Transmission	Unattended	115	13		56	2		Capacitor Banks	5	36

196	[(aa)] St. Helens, near St. Helens, OR	[(dq)] Transmission	Unattended	115						Capacitor Banks	1	24
197	St. Louis, Gervais, OR	Distribution	Unattended	57	13		23.5	2		Capacitor Banks	2	7.2
198	St. Marys, East Yard, Beaverton, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	4	12
199	St. Marys, West Yard, Beaverton, OR	[(dr)] Transmission	Unattended	230	115	13	960	3		Capacitor Banks	3	108
200	Sullivan, West Linn, OR	[(ds)] Transmission	Unattended	57	4.15		33	1				
201	Sullivan, West Linn, OR	[(dt)] Transmission	Unattended	115	13		44.8	2		Capacitor Banks	4	12
202	Summit, Government Camp, OR	Distribution	Unattended	57	13		8.4	1				
203	Summit, Government Camp, OR	Distribution	Unattended	24	13		14	1				
204	Sunset, near Hillsboro, OR	[(du)] Transmission	Unattended	115	13		400	8		Capacitor Banks	8	43.2
205	Sunset, near Hillsboro, OR	[(dv)] Transmission	Unattended	115	34.5		375	3		Capacitor Banks	5	45.6
206	Swan Island, Portland, OR	Distribution	Unattended	115	13		56	2		Capacitor Banks	4	12
207	[(ab)] Sycan, 27 mi S of Silver Lake, OR	Transmission	Unattended	500						Series Capacitor	1	546
208	Sylvan, near Portland, OR	Distribution	Unattended	115	13		22.4	1		Capacitor Banks	2	4.8
209	[(ac)] Tabor, Portland, OR	[(dw)] Transmission	Unattended	57								
210	Tabor, Portland, OR	[(dx)] Transmission	Unattended	115	13		22.4	1		Capacitor Banks	2	6
211	Tektronix, Beaverton, OR	[(dy)] Transmission	Unattended	115	13		84	3		Capacitor Banks	6	18
212	Temp A, OR	Distribution	Unattended	115	57	13	20	1				
213	Temp C, OR	Distribution	Unattended	115	57	13	28	1				
214	Temp G, OR	Distribution	Unattended	115	57	13	28	1				
215	Temp H, OR	Distribution	Unattended	115	11		21	1				
216	Tigard, Tigard, OR	Distribution	Unattended	115	13		44.8	2		Capacitor Banks	4	12
217	Tonquin, Tualatin, OR	[(dz)] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
218	Town Center, Portland, OR	[(ea)] Transmission	Unattended	115	13		56	2		Capacitor Banks	2	6
219	Trojan, near Rainier, OR	[(eb)] Transmission	Unattended	230	13		56	2				
220	[(ad)] Troutdale, BPA near Troutdale OR	Transmission	Unattended	230								
221	Tualatin, Tualatin, OR	[(ec)] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	14.4
222	Tucannon Mullan Switchyard, Tucannon Dayton, Wa	Transmission	Unattended	230	34.5	13	320	2		Capacitors/reactors	6	90
223	Twilight, Canby, OR	Distribution	Unattended	57	13		28	1	1	Capacitor Banks	4	31.2
224	University, Salem, OR	[(ed)] Transmission	Unattended	115	13		22.4	1		Capacitor Banks	2	7.2
225	Urban, Portland, OR	[(ee)] Transmission	Unattended	115	13		106.4	4		Capacitor Banks	5	39.6
226	Wacker, Portland, OR	[(ef)] Transmission	Unattended	115	13		56	2		Capacitor Banks	2	6
227	Waconda, near Hopmere, OR	Distribution	Unattended	57	13		40.6	2		Capacitor Banks	3	18
228	Wallace, Salem, OR	Distribution	Unattended	57	13		28	1		Capacitor Banks	2	6
229	Welches, near Welches, OR	Distribution	Unattended	57	24		10	1	1	Capacitor Banks	1	12
230	Welches, near Welches, OR	Distribution	Unattended	57	13		18	2		Capacitor Banks	2	6
231	[(ae)] West Portland, Lower Yard, Tigard, OR	[(eg)] Transmission	Unattended	115						Capacitor Banks	1	24
232	West Portland, Upper Yard, Tigard, OR	[(eh)] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	14.4
233	West Union, near Hillsboro, OR	[(ei)] Transmission	Unattended	115	13		56	2		Capacitor Banks	4	12
234	Willamina, near Willamina, OR	Distribution	Unattended	57	13		30.8	2		Capacitor Banks	3	7.8
235	Willbridge, Portland, OR	Distribution	Unattended	115	11		28	1				
236	Wilsonville, near Wilsonville, OR	[(ej)] Transmission	Unattended	115	13		84	3		Capacitor Banks	6	18
237	Woodburn, Woodburn, OR	Distribution	Unattended	57	13		42	2		Capacitor Banks	4	13.2

238	Yamhill, near Yamhill, OR	Distribution	Unattended	57	13		15.3	2		Capacitor Banks	1	1.8
239	Distribution Substations			8,284	1,644.4	143	2,986.25	146	4		174	611.966
240	Distribution Substations Unattended			8,284	1,644.4	143	2,986.25	146	4		174	611.966
241	Transmission Substations			24,805	4,366.53	350.28	20,915.7	261	17		285	3,078.9
242	Transmission Substations Unattended			24,805	4,366.53	350.28	20,915.7	261	17		285	3,078.9
243	Total						23,901.95					

Name of Respondent: Portland General Electric Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/11/2025	Year/Period of Report End of: 2024/ 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

Owned by PGE and operated by NextEra Energy

(c) 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.

(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

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

(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

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

(h) Concept: SubstationNameAndLocation

Owned by PGE and operated by NextEra Energy

(i) 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.

(j) 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.

(k) Concept: SubstationNameAndLocation

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

(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

Line compensation only.

(n) Concept: SubstationNameAndLocation

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

(o) Concept: SubstationNameAndLocation

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

(p) Concept: SubstationNameAndLocation

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

(q) Concept: SubstationNameAndLocation

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

(r) Concept: SubstationNameAndLocation

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

(s) 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.

(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

Switching only.

(v) 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.

(w) 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.

(x) Concept: SubstationNameAndLocation

Line compensation only.

(y) Concept: SubstationNameAndLocation

Switching only. Distribution owned by Columbia River PUD.

(z) Concept: SubstationNameAndLocation

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

(aa) Concept: SubstationNameAndLocation

Switching only. Distribution owned by Columbia River PUD.

(ab) Concept: SubstationNameAndLocation

Line compensation only.

(ac) Concept: SubstationNameAndLocation
Switching only.
(ad) Concept: SubstationNameAndLocation
Switching only. Identified location is a Bonneville Power Administration owned and operated substation at which respondent owns switching and/or regulating equipment.
(ae) Concept: SubstationNameAndLocation
Switching only.
(af) Concept: SubstationCharacterDescription
The substation has a mix of both transmission and distribution assets.
(ag) Concept: SubstationCharacterDescription
The substation has a mix of both transmission and distribution assets.
(ah) Concept: SubstationCharacterDescription
The substation has a mix of both transmission and distribution assets.
(ai) Concept: SubstationCharacterDescription
The substation has a mix of both transmission and distribution assets.
(aj) Concept: SubstationCharacterDescription
The substation has a mix of both transmission and distribution assets.
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(ax) Concept: SubstationCharacterDescription
The substation has a mix of both transmission and distribution assets.
(ay) 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: 04/11/2025	Year/Period of Report End of: 2024/ 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	8,233,799
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Administrative Serices	121 SW Salmon Street Corp	Various	2,581,163
42				